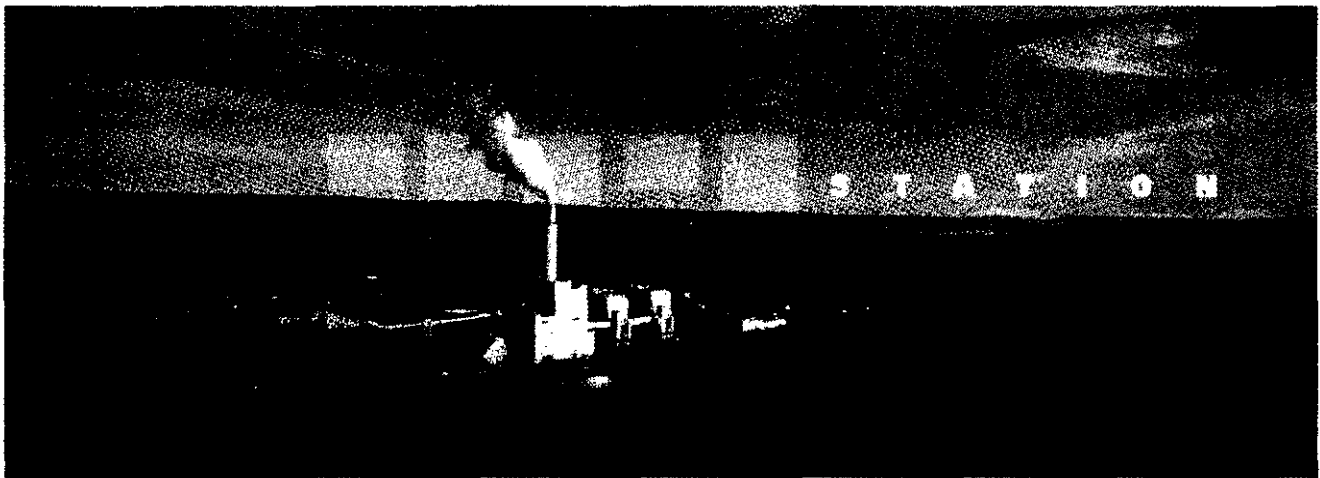


**MILLIKEN CLEAN COAL TECHNOLOGY  
DEMONSTRATION PROJECT**

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**PROJECT PERFORMANCE  
AND ECONOMICS REPORT**

**FINAL REPORT - VOLUME II of II**

**APRIL 1999**

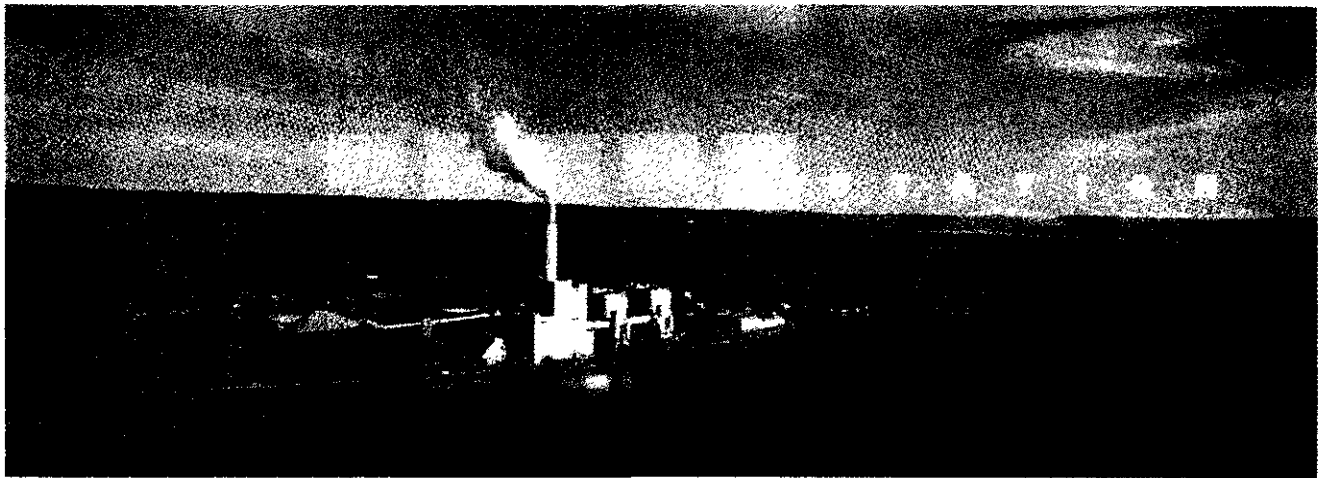
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**NEW YORK STATE ELECTRIC & GAS CORPORATION**

Chapters 5.0 - Appendices

**MILLIKEN CLEAN COAL TECHNOLOGY  
DEMONSTRATION PROJECT**

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**PROJECT PERFORMANCE  
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**NEW YORK STATE ELECTRIC & GAS CORPORATION**

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## LIST OF ABBREVIATIONS/ACRONYMS

AAQS	Ambient Air Quality Standard
ACET	Average cold end temperature
acfm	Actual cubic feet per minute
ACERC	Advanced Combustion Engineering Research Center
AER	Atmospheric and Environmental Research, Inc.
ANN	Artificial neural network
ANSI	American National Standards Institute
API	American Petroleum Institute
AQCR	Air Quality Control Region
AR	Ash resistivity
ASME	American society of Mechanical Engineers
ASTM	American Society for Testing and Materials
As	Arsenic
AVG	Average
Ba	Barium
BAF	Bioaccumulation Factor
BaP	Benzo(a)Pyrene
BC	Brine concentrator
Be	Beryllium
BMF	Biomagnification Factor
BPNN	Backpropagation neural network
BW	Borg Warner, Inc.
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
Ca <sup>+2</sup>	Calcium ion
CaCl <sub>2</sub>	Calcium chloride
CaCO <sub>3</sub>	Calcium carbonate (limestone)
CAPCIS	Corrosion and Protection Centre Industrial Services
CaO	Quicklime
CaSO <sub>4</sub>	Calcium sulfate
CaSO <sub>4</sub> ·2H <sub>2</sub> O	Calcium sulfate dihydrate (gypsum)
CCBP	Coal combustion by products
CCOFA	Concentric overfire air
CCT	Clean Coal Technology
Cd	Cadmium
CEGB	Central Electricity Generation Board
CEM	Continuous emissions monitor
CEMS	Continuous emissions monitor system
CF	Cleanliness factor

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CFD	Computational fluid dynamic
CFR	(US) code of Federal Regulations
CFS	Concentric Firing system
Cl <sup>-</sup>	Chloride ion
CKM	Chemical kinetics model
CO	Carbon monoxide
CO <sub>2</sub>	Carbon dioxide
COI	Contaminant of Interest
CPRW	Coal pipe runoff water
Cr <sup>+6</sup>	Hexavalent chromium
CRT	Cathode ray tube
DC	Direct current
DCS	Distributed control system
DOE	US Department of Energy
DOS	Disc Operating System
DP	Differential pressure
DPU	Data Processing Unit
DUCSYS®	EPRI's furnace gas dynamics model for operating transients
D <sub>50</sub>	Median particle size
ECN	Electrochemical current noise
EERC	Energy and Environmental Research Center
EIM	Electrical impedance measurement
EMP	Environmental monitoring plan
EPA	(US) Environmental Protection Administration
EPN	Electrochemical potential noise
EPRI	Electric Power Research Institute
ERA	Ecological Risk Assessment
ERDA	New York State Energy Research and Development Authority
ER-L	Effects Range-Low
ESEERCO	Empire State Electric Energy Research Corporation
ESP	Electrostatic precipitator
ESPSS	Electronic Performance Support System
E/U	NO <sub>x</sub> OUT® process enhancer to urea ratio
FD	Forced draft
FEGT	Furnace exit gas temperature
FGD	Flue gas desulfurization
FRP	Fiberglass reinforced plastic
GC	Gas chromatography
GEP	Good engineering practice

GIW	Georgia Iron Works, Inc.
H <sup>+</sup>	Hydrogen ion
H <sub>2</sub>	Hydrogen
H <sub>2</sub> O	Water
HCl	Hydrochloric acid
HCOOH	Formic acid
Hg	Mercury
HQ	Hazard quotient
HSO <sub>3</sub> <sup>-</sup>	Bisulfite
HSTC	High Sulfur Test Center
HTG™	TOPAZ® 's Historical Target Generator software
ID	Induced Draft (Fan)
ID	Inside diameter
IDI	Infilco Degremont, Inc.
ISCST	(EPA's) Industrial Source Complex Dispersion model
K	Potassium
k	One thousand
L/G	Liquid to gas ratio
LMTD	Log mean temperature difference
LNCFS	Low NO <sub>x</sub> Concentric Firing System
LOI	Loss on ignition
MACS	Miniature Acid Condensation System
MCCTD	Milliken Clean Coal Technology Demonstration
MCR	Maximum continuous rating
MCW	Maintenance Cleaning Waste Water Treatment Facility
ME	Mist Eliminator
MeHg	Methyl mercury
Mg	Magnesium
MIC	Model Input Calculations
MOC	Model Output Calculations
MS-GC	Mass spectroscopy-gas chromatography
msl	Mean sea level
MWe	Megawatt electric
MWnet	Megawatt Net
Na	Sodium
NAAQS	National Ambient Air Quality Standards
NADP	National Atmospheric Deposition Program
NERC	North American Electric Reliability Council

NH <sub>2</sub> CONH <sub>2</sub>	Urea
NH <sub>3</sub>	Ammonia
Ni	Nickel
NIST	National Institute.....
NMHC	Non-methane hydrocarbons
NO	Nitric oxide
NO <sub>2</sub>	Nitrogen dioxide
NO <sub>x</sub>	Oxides of nitrogen
NOAA	National Oceanographic and Atmospheric Administration
NSPS	New Source Performance Standards
NTU	Number of transfer units
NYSDEC	New York State Department of Environmental Conservation
NYS DOT	New York State Department of Transportation
NYSEG	New York State Electric & Gas Corporation
O <sub>2</sub>	Oxygen
O <sub>3</sub>	Ozone
OD	Outside diameter
OEM	Original Equipment Manufacturer
OPM	Online Performance Monitor
P	Phosphorus
PA	Primary air
PAH	Polycyclic Aromatic Hydrocarbons
Pb	Lead
PC	Personal computer
PCC	Process Cost Calculations
PDR	Public Design Report
PEOA	Plant Economic Optimization Advisor
PFD	Process Flow Diagram
pH	Negative logarithm of the effective hydrogen ion concentration in gram equivalents per liter
PI	Process Input
P&ID	Piping and Instrumentation Diagram
PISCES	Power Plant Integrated System: Chemical Emissions Studies
PLC	Programmable logic controller
PM	Particulate matter
PM <sub>10</sub>	Particulate matter less than or equal to 10 micrometers
PON	Program Opportunity Notice
PRSD	Percentage Standard Deviation
PSD	Prevention of Significant Deterioration
PTC	Power Test Codes (ASME)
PVC	Polyvinyl chloride
PWRF	Process waste water reclamation facility



QA	Quality assurance
QC	Quality control
RCC	Resources Conservation Co.
RIS	Rubber-in-shear
R-MCM	Regional Mercury Cycling Model
RPS	Reinforced Plastic Systems, Inc.
RTD	Remote temperature detector.....
RTT	Requirements Traceability Table
SCA	Specific collection area
SCR	Selective catalytic reduction
SDEV	Standard Deviation
SF	Service factor
SHU	Saarberg-Hölter Umwelttechnik GmbH
SMW	Solid Waste Management Facility
SNCR	Selective non-catalytic reduction
SODAR	.....
SOFA	Secondary overfire air
SO <sub>2</sub>	Sulfur dioxide
SO <sub>3</sub>	Sulfur trioxide
SO <sub>4</sub> <sup>-</sup>	Sulfate ion
SPDES	State Pollutant Discharge Elimination System
STEBBINS	The Stebbins Engineering & Manufacturing Company
SWDA	Solid waste disposal area
SWMF	Solid waste management facility
TC	Thermocouple
TCLP	Toxic Characteristics Leaching Protocol
TDH	Total dynamic head
TDS	Total dissolved solids
TEEM	Total Environmental & Energy Technology
TEFC	Totally enclosed fan cooled
TPO	Technical Project Officer
T-R	Transformer-rectifier
TRIS	Tris (hydroxy methyl) aminomethane
TRUE	Total Risk and Uncertainty Evaluation
TRV	Toxicity Reference Value
TSP	Total suspended particulates
TSS	Total suspended solids
UARG	Utility Air Regulatory Group
UCS	Unconfined Compressive Strength

US	United States
VDA	Video droplet analyzer
V-I	Voltage-current product
WDNR	Wisconsin Department of Natural Resources
WDPT	Westinghouse Distributed Processing Family of distributed control systems
WWTP	Waste Water Treatment Plant
3-D	Three dimensional

## LIST OF UNITS

acfm	Actual cubic feet per minute
amp	Ampere
bhp	Brake horsepower
Btu	British thermal unit
Btu/hr	British thermal units per hour
Btu/lb	British thermal units per pound
Btu/kWh	British thermal units per kilowatt hour
cfm	Cubic feet per minute
cm	Centimeters
cu.ft.	cubic feet
dBA	Decibels, A-scale
dscf	Standard cubic feet (dry)
dscfm	Standard cubic feet per minute (dry)
°F	Degrees Fahrenheit
ft	Feet
ft <sup>2</sup>	Square feet
fpm	Feet per minute
fps	Feet per second
g	Gram
gal	Gallon
gal/kacf	Gallons per thousand actual cubic feet
gpd	Gallons per day
gal/hr, gph	Gallons per hour
gpm	Gallons per minute
gr	Grain
hp	Horsepower
hr	hour
in	inches
in Hg	inches of mercury
in WC	Inches, water column
in WG	Inches of water, gauge
kacfm	Thousands of actual cubic feet per minute
Kscfm	Thousands of standard cubic feet per minute
kV	Kilovolt
kW	Kilowatt

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kWh	Kilowatt hour
lb/hr	Pounds per hour
lb/MM Btu	Pounds per million British thermal units
liters/hr	Liters per hour
m <sup>2</sup>	square meters
mA	Milliampere
MGD	Millions gallons per day
mg/l	Milligrams per liter
mg/m <sup>3</sup>	Milligrams per cubic meter
mills/kWh	Mills per kilowatt hour
mlb/hr	thousand pounds per hour
mm	millimeters
MM Btu	Million British thermal units
MW	Megawatt
MWe	Megawatt electric
NTU	Number of transfer units
ppm	Parts per million
ppmv	Parts per million, volumetric
psi	Pounds per square inch
psia	Pounds per square inch, absolute
psig	Pounds per square inch, gauge
rpm	Revolutions per minute
scfm	Standard cubic feet per minute
tph, tons/h	tons per hour
wt%	Percent by weight
V	Volts
VAC	Volts, alternating current
VDC	Volts, direct current
μg/m <sup>3</sup>	Micrograms per cubic meter
μm	Micrometers

## GLOSSARY OF TERMS

ACERC	Advanced Combustion Engineering Research Center
ACET	Average cold end temperature
AQCR	Air Quality Control Region
AR-196	Stebbins' chemically resistant mortar used for the absorber module
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CaCl <sub>2</sub>	Calcium chloride
CaCO <sub>3</sub>	Calcium carbonate (limestone)
CAPCIS	Corrosion and Protection Centre Industrial Services
CCT	Clean Coal Technology
CFD	Nalco Fuel Tech's computational fluid dynamics modeling technique
CKM	Nalco Fuel Tech's chemical kinetics computer model
CO	Carbon monoxide
CO <sub>2</sub>	Carbon dioxide
Densadeg®	Infilco Degremont's proprietary thickener-clarifier
DOE	US Department of Energy
Dowtherm A®	Proprietary eutectic mixture of diphenyl oxide (C <sub>12</sub> H <sub>10</sub> O) and biphenyl (C <sub>12</sub> H <sub>10</sub> )
Dowtherm J®	Proprietary mixture of isomers of an alkylated aromatic
EPA	(US) Environmental Protection Administration
EPRI	Electric Power Research Institute
ERDA	New York State Energy Research Development Authority
ES block	Stebbins Engineering insulated concrete block system used for the absorber module exterior
ESEERCO	Empire State Electric Energy Research Corporation
ESP	Electrostatic precipitator
ESPer <sup>™</sup>	EPRI's predictive model for ESP performance
FEGT	Furnace exit gas temperature
FGD	Flue gas desulfurization
FGDPRISM®	EPRI's FGD Process Model
GEP	Good engineering practice
HSTC	High Sulfur Test Center
ID	Induced Draft (Fan)
L/G	Liquid to gas ratio
Ljungstrom	Conventional rotary type regenerative air preheater

LNCFS 3	Low NO <sub>x</sub> Concentric Firing System 3, ABB-CE's low NO <sub>x</sub> combustion process
LOI	Loss on ignition
MCCTD	Milliken Clean Coal Technology Demonstration
NAAQS	National Ambient Air Quality Standards
NADP	National Atmospheric Deposition Program
NERC	North American Electric Reliability Council
NH <sub>3</sub>	Ammonia
NMHC	Non-methane hydrocarbons
NO	Nitrogen oxide
NO <sub>2</sub>	Nitrogen dioxide
NO <sub>x</sub>	Oxides of nitrogen
NO <sub>x</sub> OUT®	Process, by Naico Fuel Tech, urea-based chemical and mechanical system for cost-effective NO <sub>x</sub> reduction
NO <sub>x</sub> OUT A®	Proprietary urea solution for NO <sub>x</sub> OUT® process
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
NYSEG	New York State Electric & Gas Corporation
Pb	Lead
PCGC-3	ACERC's 3-dimensional coal combustion computer model
PDR	Public Design Report
PFD	Process Flow Diagram
P&ID	Piping & Instrumentation Diagrams
PISCES	Power Plant Integrated System: Chemical Emissions Studies, an EPRI program
PON	Program Opportunity Notice
PSC	New York State Public Service Commission
PSD	Prevention of Significant Deterioration
ROW	Right-of-way
SADCA	New York State Acid Deposition Control Act
SCR	Selective catalytic reduction
SEMPLETE™	Stebbins Engineering's proprietary ceramic tile material
S-H-U	Saarberg-Hölter Umwelttechnik GmbH
SNCR	Selective non-catalytic reduction
SO <sub>2</sub>	Sulfur dioxide
SPDES	State Pollutant Discharge Elimination System
STEBBINS	The Stebbins Engineering & Manufacturing Co.
SWMF	Solid waste management facility
TEEM	Total Environmental & Energy Management

TOPAZ®	DHR Technology's total plant advisor
TPO	Technical Project Officer
TRUE	EPRI's Total Risk and Uncertainty Evaluation model for evaluation of the movement of hazardous pollutants through environmental ecosystems
US	United States

**5.0 ENVIRONMENTAL  
PERFORMANCE**



## **5.0 ENVIRONMENTAL PERFORMANCE**

### **5.1 INTRODUCTION**

This section of the Project Performance and Economics Report discusses the environmental impacts of the technology demonstrated in the project. The expected environmental benefits resulting from commercial implementation of the technologies are discussed. The project's Environmental Monitoring Reports are summarized. Each by-product and waste stream is discussed including yield, composition, preferred method of disposal, etc. Potential markets for marketable by-products and disposal strategies for non-salable waste streams are addressed. Potential environmental problems not discussed elsewhere are addressed in this section.

To implement the Environmental Performance portion of the Milliken Clean Coal Technology Demonstration Project, NYSEG identified the following projects:

- 1.03.69.02 Milliken By-Product Utilization Studies
- 1.03.69.04 Chemical Emissions Measurement Program at Milliken's Unit #2
- 1.03.69.07 Milliken Environmental Monitoring Program
- 1.03.69.13 Innovative Waste Liners
- 1.03.69.18 Milliken Water Toxics Treatment & Characterization
- 1.03.69.21 Milliken Post-Retrofit "TRUE" Evaluation
- 1.03.69.22 Milliken-Air Toxics & Emissions Characterization
- 1.03.69.23 Land and Water Quality Studies

The scope of each of these projects is summarized below.

#### **MILLIKEN BY-PRODUCT UTILIZATION STUDIES**

The principal products covered in these studies included flyash, calcium chloride and gypsum. Flyash, which is marketed as concrete additive, can be adversely affected by the installation of the Low NO<sub>x</sub> Concentric Firing System (LNCFS) and the Selective Non-Catalytic Reduction (SNCR) process. Increased carbon and ammonia concentrations can result in unmarketable ash. One objective of the By-Product Utilization Study was to analyze flyash both pre- and post- LNCFS/SNCR installation to determine impacts on the sale of ash due to changes in ash composition.

Two new by-products were generated as a result of the operation of the flue gas desulfurization (FGD) system: gypsum and calcium chloride brine. Separate reports for each by-product include surveys and market assessments of potential usage of these products in the United States as well as cost assessments and design considerations associated with operating experience for their handling and conditioning.

#### **MILLIKEN STATION ENVIRONMENTAL MONITORING PROGRAM**

An environmental monitoring plan (EMP) was developed in support of NYSEG's application to the U.S. Department of Energy (DOE) for project funding through the

Clean Coal Technology (CCT) Program. The plan provided a comprehensive description of monitoring programs that were implemented in response to permitting agencies' requirements (compliance monitoring), and to track the performance of the FGD system and the other aspects of the project for the purpose of demonstrating the technologies (supplemental monitoring). Quarterly environmental monitoring reports were developed in support of NYSEG's requirements to the U.S. Department of Energy (DOE) for project funding through the Clean Coal Technology (CCT) Program. The environmental monitoring reports provide a comprehensive description of the environmental monitoring programs that occurred during each quarter of the demonstration program as a response to permitting agencies' requirements (compliance monitoring). The reports also address other environmental aspects of the project for the purpose of demonstrating these technologies.

### **INNOVATIVE WASTE LINERS**

NYSEG submitted to EPRI a case study for NYSEG's Kintigh Station solid waste disposal liner installation. The results of this study, which was a part of the demonstration phase of the project but not an element of the DOE scope of work, are presented for reference in summary form.

### **CHEMICAL EMISSIONS MEASUREMENT PROGRAM AT MILLIKEN'S UNIT #2**

The intent of this program was to characterize baseline air toxic emissions prior to the installation of the clean coal demonstration technologies. The program scope included determining removal efficiencies for key air toxic compounds (Hg, Ni, As, Be, Cd, Cr<sup>+6</sup>, BaP, dioxins and furans) and developing a system mass balance for the metals.

### **MILLIKEN WATER TOXICS TREATMENT & CHARACTERIZATION**

The scope of this program included evaluating heavy metals removal in the FGD bleed stream and determining parameters for controlling mercury removal and total treatment efficiency. The scope also included determining the ultimate disposal and treatment of heavy metal sludge and costs for entire treatment.

### **MILLIKEN POST RETROFIT "TRUE" EVALUATION**

The scope of this program included using the EPRI "TRUE" (Total Risk and Uncertainty Evaluation) model to assess the potential for the CCTD to mitigate transferral of toxic materials from the plant site to the ambient environment. Possible transferral routes included in the study were stack emissions and contaminated water discharge streams. The risk management approach was used to demonstrate the capability of the Milliken project to mitigate health and ecological risks in the vicinity of the station. The "TRUE" model allows a comprehensive evaluation of the movement of hazardous pollutants into and through many environmental pathways and the manners in which humans and ecosystems may be exposed to these pollutants.

## **MILLIKEN AIR TOXICS & EMISSIONS CHARACTERIZATION**

The scope of this program included characterizing baseline air toxic emissions following the installation of the CCTD. The program scope included determining removal efficiencies for key air toxic compounds (Hg, Ni, As, Be, Cd, Cr<sup>+6</sup>, BaP, dioxins and furans) and developing a system mass balance for the metals.

## **LAND AND WATER QUALITY STUDIES**

The intent of this program was to analyze and characterize the liquid and solid wastes generated by Milliken Station after the CCTD had been installed. The analysis was to include physical, chemical and mineralogical composition of the wastes as well as the leachate they generated.

One or more separate reports were published which presented the findings of each of these projects. The following sections summarize each of these reports.

## **5.2 MILLIKEN ENVIRONMENTAL MONITORING PROGRAM**

### **5.2.1 INTRODUCTION**

The Milliken Clean Coal Technology Demonstration project added a forced oxidation, formic acid-enhanced wet limestone FGD system to Milliken Station which was expected to reduce SO<sub>2</sub> emissions by at least 90%. The project also consisted of combustion modifications and selective non-catalytic reduction (SNCR) technology to reduce NO<sub>x</sub> emissions. Goals of the demonstration included up to 98% SO<sub>2</sub> removal efficiency while burning high-sulfur coal, 30% reductions in NO<sub>x</sub> emissions through combustion modifications, additional reductions using SNCR technology, production of marketable commercial-grade gypsum and calcium chloride by-products to minimize solid waste disposal, and zero wastewater discharge.

An environmental monitoring plan (EMP) was developed in support of NYSEG's application to the U.S. Department of Energy (DOE) for project funding through the Clean Coal Technology (CCT) Program. The plan provided a comprehensive description of monitoring programs that were implemented in response to permitting agencies' requirements (compliance monitoring), and to track the performance of the FGD system and the other aspects of the project for the purpose of demonstrating the technologies (supplemental monitoring).

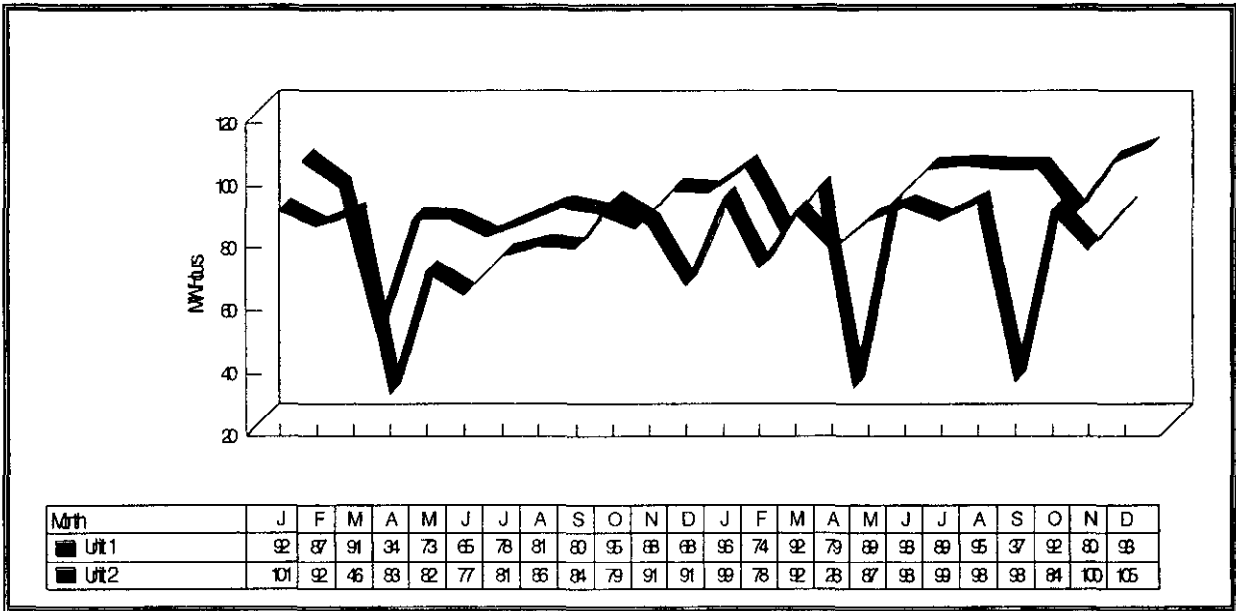
Quarterly environmental monitoring reports were developed in support of NYSEG's requirements to the U.S. Department of Energy (DOE) for project funding through the Clean Coal Technology (CCT) Program. The environmental monitoring reports provided a comprehensive description of the environmental monitoring programs that occurred during each quarter of the demonstration program as a response to permitting agencies' requirements (compliance monitoring). The reports also addressed other environmental aspects of the project for the purpose of demonstrating these technologies. The following discussion recaps the project's environmental performance throughout the demonstration period. Complete quarterly reports, which include all the details of the environmental monitoring program, are available upon request from DOE.

During the course of the Milliken Station Environmental Monitoring Program, many changes were taking place. The most significant design modifications occurred on December 11, 1994 and June 20, 1995, when both generating units at the Milliken Station were partially and/or totally converted to the new flue gas desulfurization (FGD) systems. Because of these developments, the most significant periods (i.e., the periods when data were closely scrutinized) were the period from February 1993 (air monitoring startup) through December 10, 1994 (Period I) and the period from June 20, 1995 through December 31, 1996 (Period II). During Period I (Feb. 1993 - Dec. 10, 1994) all units at the Milliken Station were operating using the earlier non-scrubbed stacks, while during Period II (June 20, 1995-Dec. 31, 1996) all Milliken units were operating using the new FGD process.

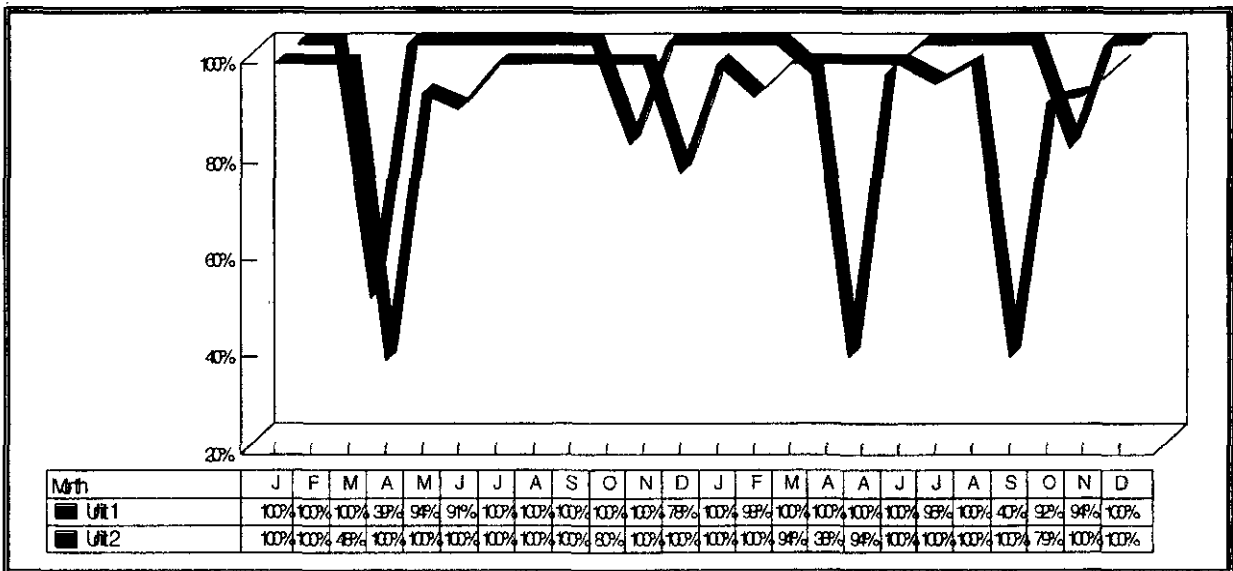
Once the new LNCFS-3 burners on both boilers at Milliken Station were fully tuned and operational, NO<sub>x</sub> emissions were significantly reduced while minimizing the amount of unburned carbon contained in the flyash. At full boiler load there was good agreement between measured and predicted NO<sub>x</sub> emissions and LOI at various economizer O<sub>2</sub> levels and various mill classifier speed settings. At reduced loads (120 & 90 MW), measured NO<sub>x</sub> and LOI levels were lower than predicted.

Availability and monthly load for both of Milliken's Units for 1995 and 1996 are listed in Figure 5.2-1 and 5.2-2 respectively.

**FIGURE 5.2-1  
Milliken Station Net Generation  
1996 - 1997**



**FIGURE 5.2-2  
Milliken Station Availability  
1996 - 1997**



## **SUMMARY OF PROJECT OPERATING HISTORY**

FGD construction was completed in December 1994. Start up testing of various FGD components continued into mid-January 1995. On January 17, 1995, the Unit 2 FGD module became fully operational and began scrubbing flue gas. The Unit 1 FGD module was capable of operating but required a boiler outage to make the final flue gas duct connections and to install the larger induced draft fans. The Unit 1 outage occurred during April - June of 1995. Initial start up of the Unit 2 scrubber (January 1995) revealed a problem with the gypsum dewatering system. The centrifuges which dewater the gypsum had problems with the loading and peeling cycles. This initially resulted in shutting down the Unit 2 FGD module for two days (Jan. 18-20) and then curtailing the production of gypsum for approximately two months. During this period, NYSEG engineering redesigned the blade and control logic responsible for peeling the gypsum from the centrifuge drum.

On February 28, 1995, the Unit 2 boiler was down for a screen outage. During the outage an inspection was made of the FGD system. No major problems were identified. Visual inspections of the mist eliminators revealed no scale formation or plugging.

On April 18, 1995, the Unit 1 boiler was shut down to connect the flue gas duct to the FGD module. Work during the outage progressed as expected with the unit returning to service on June 16, 1995. Initially flue gas from Unit 1 was exhausted through the FGD by-pass so burner adjustments could be completed. On June 20, 1995, the Unit 1 FGD module went into service. Milliken Station had full scrubbing capabilities and continued to operate throughout the remainder of 1995.

The waste water treatment system and brine concentrator initially were not required since the chloride level in the FGD liquor had not reached 40,000 ppm. Based on the measured rate of increase in chlorides, the need for the brine concentrator was not expected to occur until June 1995. The brine concentrator began operating on July 20, 1995. However, the brine concentrator had problems with continuous operation which necessitated temporary approval from the NYSDEC to discharge the brine feedwater into the Process Waste Reclamation Facility.

The 1995 annual maintenance outage for Unit 2 had to be moved from early spring to September to accommodate the need to perform remedial work on the heat pipe air heater. The rescheduling of the outage affected the test activities on the burners, precipitator and FGD system. This resulted in the delay of the testing to mid-October 1995.

The low sulfur FGD tests were delayed until October 16, 1995 due to repairs to the heat pipe air heater (Sept. 15 - Oct.2) and the time needed to allow the FGD system to reach equilibrium. The low sulfur test protocol for the FGD system met EPRI and DOE test requirements for a low sulfur fuel. The low sulfur test was completed on November 22, 1995. The following additional tests were performed during the month of October 1995:

LNCFS-3 burner verification and performance, post-retrofit electrostatic precipitator and NYSDEC stack certification testing.

During 1995, no problem areas were identified concerning environmental regulations or permit conditions due to the operation and performance of the equipment being demonstrated under the CCTD at Milliken Station. One noncompliance was filed with the New York State Department of Environmental Conservation. This occurred during the fourth quarter of 1995. The noncompliance occurred on December 12 from outfall 001A sanitary wastes when the total chlorine limit of 5.0 mg/l was exceeded with a value of 5.5 mg/l.

During the first quarter of 1996, the Unit 2 annual outage occurred between March 15-31. A damper was installed to bias the flue gas between the primary and secondary air heaters. The damper was intended to help moderate flow through the heat pipe, increasing its performance. In addition the heat pipe was cleaned and inspected and an Infrasonic soot blower was installed on the A heat pipe. The Unit 1 annual outage occurred between April 12 and May 2. Unit 1 was also was down in early June for a throttle valve repair.

Design coal FGD testing began on May 13, 1996. The initial testing began with no formic acid with a chloride concentration of 30,000 ppm. The testing documented the SHU performance guarantee of 95% sulfur removal at seven pump operation. High velocity tests had to be delayed in May due to unseasonably high temperatures which placed increased demands on plant load. In addition, the design coal FGD testing was delayed in June due to a drop in sulfur content in the fuel, due to production quality at the mine. NYSEG worked with CONSOL to identify a substitute coal with a higher sulfur content and eventually came up with a 50/50 blend of washed and unwashed Blacksville Coal. A test burn which began on July 2, 1996 resulted in no obvious problems in the operation of the plant and the sulfur content of the fuel increased to 2.5%. Design coal tests resumed on August 19, following the PISCES Air Toxics Tests which occurred during the first two weeks of August 1996.

Again in 1996, no problem areas were identified concerning environmental regulations or permit conditions due to the operation and performance of the equipment being demonstrated under the CCTD at Milliken Station.



## **5.2.2 AIR QUALITY MONITORING**

The following discussion summarizes the operating emissions at the stack and the findings of the local ambient air monitoring network.

### **STACK EMISSIONS MONITORING**

New continuous emission monitoring systems (CEMS) were installed at Milliken Station, replacing the existing certified systems on the old brick chimneys. The new CEMS are located on the FGD and bypass stack flues, approximately 66 feet from the top of the 375 foot stack. Certification test data were presented in two Certification Reports dated January 1995 and February 1995 for the Milliken Station FGD bypass and Unit #2 stack, respectively. On June 25-28, 1995 CEMS certification tests were performed on the Unit 1 FGD stack. A report was issued on July 12 certifying the CEM system for Unit 1. CEMS certification tests were completed in accordance with the methods and procedures specified in 40 CFR Part 75.

The FGD CEMS for Unit 2 became fully operational and certified by the end of the first quarter of 1995. Initially, Unit 1 continued to use the CEMS installed on the existing chimney while Unit 2 emissions were monitored using the by-pass CEMS on the FGD stack. Once the FGD system became operational on January 17, 1995, Unit 2 was monitored via the Unit 2 FGD absorber CEMS. At the end of the second quarter of 1995, FGD CEMS for both units were fully operational. As with Unit 2, Unit 1 at first exhausted flue gas through the FGD bypass. On June 29, 1995, the flue gas was directed through the Unit 1 FGD absorber module.

In the third quarter of 1995, both Milliken Station brick chimneys were demolished. NYSDEC's Permit to Construct, Special Condition III, Testing Requirements required stack testing within 180 days after initial operation for emissions of SO<sub>2</sub>, NO<sub>x</sub>, TSP, CO<sub>2</sub> and opacity for each boiler. NYSEG conducted the required emissions testing for both units on October 17 and 18, 1995.

The permit issued by the NYSDEC to allow construction of the Milliken CCTD project had a specific condition requiring stack testing for emissions of SO<sub>2</sub>, NO<sub>x</sub>, TSP, CO and opacity for each boiler. All stack testing had to be completed in accordance with protocols approved by NYSDEC in advance of testing.

Stack testing of Unit 1 stack was conducted on October 17, 1995. The unit was operated at normal full load while firing a typical pulverized bituminous coal. The FGD was operating at design operating conditions. The particulate matter (PM) results indicate an average measured emission concentration of .0079 grains per dry standard cubic foot (gr/dscf) and .0188 pounds per million British thermal units (lb/mmBTU). The average PM emission rate of .0188 lb/mmBTU is well below the NYSDEC permit limit of 0.1 lb/mmBTU. The average CO concentration was 2.4 ppm and the average emission rate was 4.15 lb/hr and .0029 lb/mmBTU. The average SO<sub>2</sub> concentration was 110.4 ppm

and the average emission rate was .3045 lb/mmBTU. The average concentration of NO<sub>x</sub> was 192.7 ppm and the average emission rate was .3823 lb/mmBTU.

Stack testing of Unit 2 stack was conducted on October 18, 1995. The unit was operated at normal full load while firing a typical pulverized bituminous coal. Burner adjustments on Unit 2 were made to accommodate simultaneous testing to the electrostatic precipitator. The FGD system was operating at design operating conditions. The particulate matter results indicate an average measured emission concentration of .0080 grains per dry standard cubic foot (gr/dscf) and .0170 pounds per million British thermal units (lb/mmBTU). The average PM emission rate of .0170 lb/mmBTU is well below the NYSDEC permit limit of 0.1 lbs/mmBTU. The average CO concentration was 2.1 ppm and the average emission rate was 3.48 lb/hr and .0023 lb/mmBTU. The average SO<sub>2</sub> concentration was 244.5 ppm and the average emission rate was .6018 lb/mmBTU. The average concentration of NO<sub>x</sub> was 315.6 ppm and the average emission rate was .5586 lb/mmBTU.

## **AMBIENT AIR AND METEOROLOGICAL MONITORING**

This ambient monitoring program was performed to fulfill both compliance monitoring and supplemental monitoring objectives. In the permit to construct issued for the Milliken Station CCTD project, the New York State Department of Environmental Conservation (NYSDEC) required monitoring of ambient SO<sub>2</sub>, PM<sub>10</sub> and NO<sub>x</sub>. Additional parameters (O<sub>3</sub>, TSP and metals) were included in the monitoring program to further demonstrate and document the effects of the new technology on the local ambient air quality. The ambient air quality and meteorological monitoring program are described and the four years of data collected during the Clean Coal Technology (CCT) Program are analyzed in the following sections.

### **Monitoring Network Design/Configuration**

During the years 1991 and 1992 NYSEG initiated an ambient air quality and meteorological monitoring program which subsequently began operations and data collection during February 1993 (approximately two years prior to the Milliken Station CCT scrubber retrofit). The air monitoring program continued through December 1996 (approximately 1.5 years after completion of the Milliken Station CCT scrubber retrofit). The 4-year ambient monitoring program was conducted by NYSEG for the following primary purposes:

- to demonstrate compliance with ambient air quality standards;
- to comply with the NYSDEC's permit conditions;
- to provide actual comparisons between ambient levels of SO<sub>2</sub>, and O<sub>3</sub> before and after the scrubber retrofit,
- to demonstrate the scrubber's effectiveness in reducing ambient levels of SO<sub>2</sub> and NO<sub>x</sub>.

In order to site the locations for the ambient monitoring program, NYSEG performed a dispersion modeling analysis in 1991 for three pollutants (SO<sub>2</sub>, NO<sub>2</sub> and NH<sub>3</sub>) to predict maximum ambient air impacts associated with the new 375-foot Milliken Station stack. The analysis employed two models: the U.S. EPA's Industrial Source Complex dispersion model (ISCST) and the U.S. EPA's COMPLEX-1 dispersion model. The former was used to predict maximum impacts in terrain below stack top elevation, and the latter, to predict maximum impacts at elevations greater than plume height. Impacts in terrain at elevations between stack top and plume height were evaluated by modeling with both ISCST and COMPLEX-1, and using the more conservative of the resulting two predictions to represent maximum impacts for those regions.

NYSEG's modeling analysis identified three major impact areas, as follows:

- West of Lake Road, roughly 1600 meters northeast of the plant -- the area of the highest 3-hour average impact;
- In the vicinity of McQuiggin Corners, approximately 3200 meters north of the plant; this general area included predicted impacts for 3-hour, 24-hour and annual averaging periods;
- Southeast of Milliken Station, an area bounded by Route 34B, Lansing Station Road, Ludlow Road and Algerine Road (approximately 3600 meters southeast of the plant); this area included the maximum for the 24-hour and annual averaging periods.

The final network design consisted of three ambient air quality/meteorological sites, plus a central meteorological site consisting of a 100-meter meteorological tower and an acoustic SODAR.

The central meteorological site contained a 100-meter tower monitoring three levels of wind speed and wind direction, three levels of vertical wind speed, three levels of temperature difference, ambient temperature, solar radiation and net radiation. Wind turbulence data were derived from the horizontal wind direction (sigma theta) and vertical wind speed (sigma W) by an on-site Odessa DSM 3260 data logger. Associated with the tower was a Remtech acoustic SODAR monitoring wind speed, wind direction, and turbulence in eight atmospheric layers. The air quality monitoring sites each contained monitors for SO<sub>2</sub>, NO<sub>2</sub>, TSP, PM<sub>10</sub> and 10-meter wind speed, wind direction and temperature. One of these sites (North site) also monitored O<sub>3</sub>. Tables 5.2-1 and 5.2-2 list the measurements and instrumentation for each site and parameter. Configuration, siting, operation, data processing and quality assurance/quality control practices conform to EPA provisions.

The ambient monitoring program was accepted and approved by the NYSDEC. Per NYSDEC's requirements all data collected (air quality and tower meteorological data) were telemetered to DEC's central computer on a daily basis. The air monitoring network was audited on a quarterly basis by representatives of the NYSDEC and ENSR.

Tables listing SO<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub> and flue gas flow by hour for each day of the quarter are presented in each of the published quarterly environmental monitoring reports. All data are available upon request from NYSEG.

### **Data Summary/Analysis**

The highest hourly average SO<sub>2</sub> concentration measured during the 4-year period at the North Site was 250 ppb, with a peak 3-hour running average of 206 ppb (41% of AAQS) and a peak 24-hour running average of 61 ppb (44% of AAQS). The hourly SO<sub>2</sub> average for the 4-year period was 6 ppb (annual AAQS 30 ppb). The highest hourly average NO<sub>2</sub> and NO<sub>x</sub> concentrations for the North Site were 43 ppb and 83 ppb respectively, with a 4-year average of 5 ppb for NO<sub>2</sub> and 7 ppb for NO<sub>x</sub> (annual AAQS for NO<sub>2</sub> is 50 ppb). The highest hourly average ozone concentration measured at the North Site during the period was 101 ppb (84% of AAQS), with a maximum annual average (1994) of 33 ppb. The highest 24-hour PM<sub>10</sub> concentration during this 4-year period was 64.2 µg/m<sup>3</sup> (43% of AAQS). The highest 24-hour TSP concentration was 50.5 µg/m<sup>3</sup> (34% of the secondary AAQS).

The highest hourly average SO<sub>2</sub> concentration measured during this period at the East Site was 210 ppb, with a peak 3-hour running average of 144 ppb (29% of AAQS) and a peak 24-hour running average of 43 ppb (31% of AAQS). The hourly SO<sub>2</sub> average for the 4-year period was 6 ppb (annual AAQS 30 ppb). The highest hourly average NO<sub>2</sub> and NO<sub>x</sub> concentrations for the East Site were 51 ppb and 279 ppb respectively, with a 4-year average of 5 ppb for NO<sub>2</sub> and 7 ppb for NO<sub>x</sub> (annual AAQS for NO<sub>2</sub> is 50 ppb). The highest 24-hour PM<sub>10</sub> concentration during this 4-year period was 62.2 µg/m<sup>3</sup> (41% of AAQS). The highest 24-hour TSP concentration was 52.2 µg/m<sup>3</sup> (35% of the secondary AAQS).

The highest hourly average SO<sub>2</sub> concentration measured during this period at the South Site was 260 ppb with a peak 3-hour running average of 218 ppb (44% of AAQS) and a peak 24-hour running average of 70 ppb (50% of AAQS). The hourly SO<sub>2</sub> average for the 4-year period was 7 ppb (annual AAQS 30 ppb). The highest NO<sub>2</sub> and NO<sub>x</sub> hourly concentrations were 59 ppb and 257 ppb respectively, with a 4-year average of 6 ppb for NO<sub>2</sub> and 7 ppb for NO<sub>x</sub> (annual AAQS for NO<sub>2</sub> is 50 ppb). The highest 24-hour PM<sub>10</sub> concentration during this 4-year period was 50.4 µg/m<sup>3</sup> (34% of AAQS). The highest 24-hour TSP concentration during the period was 51.9 µg/m<sup>3</sup> (35% of the secondary AAQS).

The predominant wind directions during the 4-year period (1993-1996) from the central tower were from the NW-NNW and SE-SSE. The predominant winds at all three levels of the central meteorological tower follow very closely the valley orientation surrounding NYSEG's Milliken Station. Annual wind roses for the years 1993-1996 show consistent wind patterns each year very similar to the overall 4-year wind patterns.

During the course of the 4-year air monitoring program, many changes were taking place within NYSEG's Milliken Station. The most significant design modifications occurred on

December 11, 1994 and June 20, 1995, when both generating units at the Milliken Station were partially and/or totally converted to the new FGD systems. Because of these developments, the most significant periods (i.e., the periods when data were closely scrutinized) were the period from February 1993 (air monitoring startup) through December 10, 1994 (Period I) and the period from June 20, 1995 through December 31, 1996 (Period II). During Period I (Feb. 1993 - Dec. 10, 1994) all units at the Milliken Station were operating using the earlier non-scrubbed stacks, while during Period II (June 20, 1995-Dec. 31, 1996) all Milliken units were operating using the new FGD process. The period from Dec. 11, 1994 through June 19, 1995 was a period of transition and frequent configuration change at the station.

During these periods of redesign at the Milliken Station quite noticeable changes were also taking place in the ambient levels of the various pollutants being measured throughout the NYSEG air monitoring network. These changes are described below.

### Sulfur Dioxide (SO<sub>2</sub>)

Analyzing the four years of SO<sub>2</sub> data collection, figures 5.2-3 and 5.2-4 present the maximum hourly SO<sub>2</sub> concentration and 3-hour running peak concentrations respectively for each of the three air quality monitoring sites for the calendar years 1993 through 1996. In general, a significant downward trend is observed between the maximum concentrations in 1993 and 1994 versus those of 1995 and in particular 1996. Figure 5.2-5 and Figure 5.2-6 present the 24-hour running peak and annual hourly average SO<sub>2</sub> concentrations respectively for each site for the calendar years 1993 through 1996. Once again, a significant reduction in average SO<sub>2</sub> levels is observed between calendar years 1993 and 1994 versus 1995 and 1996.

Looking at SO<sub>2</sub> levels during the two critical periods defined previously (Period I from February 1993-Dec. 10, 1994 and Period II from June 20, 1995-Dec. 31, 1996) which focus on the pre-and post-FGD scrubbing periods, one again sees significant SO<sub>2</sub> changes (reductions). Figure 5.2-7 illustrates diurnal SO<sub>2</sub> concentration curves for each hour of the day for the three air quality monitoring sites. The upper plot illustrates the diurnal SO<sub>2</sub> curve for the period Feb. 1993 through Dec. 10, 1994, while the lower plot presents the SO<sub>2</sub> distributions for the period June 20, 1995 through Dec. 31, 1996. These two plots clearly show a significant reduction in ambient SO<sub>2</sub> levels at the three NYSEG air monitoring sites when comparing the pre- and post-scrubbing periods. In general, measurements showed the SO<sub>2</sub> levels to be lower by an average of 40-50% from Period I to Period II.

### Nitrogen Dioxide (NO<sub>2</sub>) & Ozone (O<sub>3</sub>)

Analyzing the four years of NO<sub>2</sub> data collection, figure 5.2-8 presents the maximum NO<sub>2</sub> 1-hour concentrations for each of the three sites for the calendar years 1993 through 1996. In general, a subtle downward trend can be observed during 1996 versus the previous three years. Figure 5.2-9 also presents the annual average NO<sub>2</sub> concentrations

for each site for each of the calendar measurement years 1993 through 1996. No obvious annual average changes are evident from year to year for each of the three sites.

Comparing the NO<sub>2</sub> levels during the two critical periods (pre- and post-scrubbing) some reductions in NO<sub>2</sub> levels are discernible. Figure 5.2-10 presents the diurnal NO<sub>2</sub> concentration curves for each hour of the day for the three sites. The upper plot presents the diurnal NO<sub>2</sub> levels for the period Feb. 1993 through Dec. 10, 1994, while the lower plot presents the NO<sub>2</sub> distributions for the period June 20, 1995 through Dec. 31, 1996. A comparison of these NO<sub>2</sub> diurnal concentration curves reveals modest reductions in ambient NO<sub>2</sub> levels at two of the sites (North and South) and little, if any, change at the third site (East) between the pre- and post-scrubbing periods.

Comparing the O<sub>3</sub> concentration levels between the two critical periods (pre- and post-scrubbing) a slight reduction in the ambient O<sub>3</sub> levels can be identified. Figure 5.2-8 presents the diurnal O<sub>3</sub> concentration curves for each hour of the day for the North site. The upper plot presents the diurnal O<sub>3</sub> levels for the period Feb. 1993 through Dec. 10, 1994, while the lower plot presents the O<sub>3</sub> distributions for the period June 20, 1995 through Dec. 31, 1996. A comparison of these O<sub>3</sub> diurnal concentration curves reveals slight reductions in ambient O<sub>3</sub> levels between the pre-and post-scrubbing periods.

As previously shown, the changes in ambient levels of SO<sub>2</sub> between the pre- and post-scrubbing periods were significant (approximately 40-50% reductions). The changes in NO<sub>2</sub> and O<sub>3</sub> ambient levels, although also apparently being reduced, were not as significant. In order to determine whether the changes in NO<sub>2</sub> and O<sub>3</sub> ambient levels were statistically significant, a series of T-tests were performed on each database to help determine the significance of each parameter change for each site. The T-test used is defined in the Code of Federal Regulations (CFR) Part 60, Appendix C, amended/modified for use in this ambient data application. Table 5.2-3 presents the results of the T-tests performed on the three NO<sub>2</sub> monitoring sites and the one O<sub>3</sub> site for the two critical periods (pre- and post-scrubbing).

The results of the NO<sub>2</sub> statistical T-tests indicate that with 99.95% confidence, the changes (reductions) in NO<sub>2</sub> concentrations at the North and South sites between Periods I and II are considered significant. However, the changes (reductions) in NO<sub>2</sub> concentrations at the East site for the same periods are considered insignificant. The T-test results for the North and South sites in each case indicate the calculated T-value to be greater than the T<sup>1</sup>-value as determined by the degrees of freedom of the comparative tests. By definition (40 CFR, Appendix C, Part 60), if T is greater than T<sup>1</sup>, then the difference in the average values of each data set is considered to be significant. With respect to the East site NO<sub>2</sub> data comparison, the calculated T-value was found to be less than the various confidence level T<sup>1</sup> values, indicating an insignificant change in the ambient NO<sub>2</sub> levels.

Similarly, the same statistical tests were conducted on the ozone (O<sub>3</sub>) data collected at the North Site during the same periods. The results of the O<sub>3</sub> statistical T-test are also presented in table 5.2-3. The results of the T-test indicate that with 95% confidence the changes (reductions) in ambient levels of O<sub>3</sub> from Period I (Feb. 1993-Dec. 10, 1994) to Period II (June 20, 1995-Dec. 31, 1996) are considered significant. The T-test results show the calculated T-value to be less than the 99.95% confidence T<sup>1</sup>-value. However, the calculated T-value was found to be greater than the 95% confidence T<sup>1</sup>-value. These results indicate that with a 95% confidence level a significant change in ambient levels of O<sub>3</sub> had occurred.

In summary, based upon the statistical T-tests conducted, the changes (reductions) in ambient levels of NO<sub>2</sub> between the pre- and post-scrubbing periods are considered significant for the North and South sites, but insignificant for the East site. The changes (reductions) in ambient levels of O<sub>3</sub> between the pre- and post-scrubbing periods are also considered to be significant.

#### Total Suspended Particulates (TSP) & Inhalable Particulate (PM<sub>10</sub>)

Similar data comparisons were made of the total suspended particulate (TSP) and inhalable particulate (PM<sub>10</sub>) data for the periods of sampling (i.e., PM<sub>10</sub>: Feb. 1993-Dec. 1996 and TSP: Dec. 1994-Dec. 1996). No conclusive changes in the ambient levels could be detected for either parameter.

### **SUMMARY / CONCLUSIONS**

As part of NYSEG's Milliken Station Clean Coal Technology Demonstration project, a flue gas desulfurization system was added as well as modifications to the combustion system and electrostatic precipitator. These modifications have resulted in a net reduction in emissions from Milliken.

The burners were replaced with Low NO<sub>x</sub> Concentric Firing System Level 3 (LNCFS-3) burners to reduce NO<sub>x</sub> emissions while maintaining high combustion efficiency and acceptable fly ash loss on ignition (LOI). The achievable annual NO<sub>x</sub> emissions, estimated using long-term measurements, were .61 lbs/mmBtu for baseline operations and .39 lbs/mmBtu for post retrofit operations. This equates to a 36% reduction in NO<sub>x</sub> emissions.

The electrostatic precipitators (ESP) on the two 160 MWe boilers were upgraded to accommodate the wet flue gas desulfurization system. Upgrades of the ESP on each unit consisted of replacement of the internals and retirement of part of the original ESP. Performance tests conducted on the original and modified ESPs documented the improved performance of the retrofit. The modified ESP with less than one-half of the collection plate area has better removal efficiency than the original unit. The voltage-current product data indicate that the power requirement is 25% less than that of the original ESP.

The flue gas desulfurization system became fully operational in June 1995. The average removal efficiency for the system is approximately 88%. This includes testing periods in which operating conditions were varied to determine effects on removal efficiencies. The FGD system has essentially operated during all periods of boiler operation except startup and shutdown.

The ambient levels of SO<sub>2</sub>, NO<sub>2</sub>, O<sub>3</sub>, TSP and PM<sub>10</sub> at all sites were found to be below ambient air quality standards throughout the entire 4-year ambient monitoring program. Analyzing the ambient air quality data collected in the surrounding area for the two years prior to NYSEG's Milliken Station FGD retrofit and the year and a half after the retrofit, significant changes to the ambient air quality were identified. The ambient SO<sub>2</sub> levels showed a reduction by an average of 40-50% over the course of the 4-year air monitoring study. The ambient NO<sub>2</sub> levels also were reduced by an average of 10-15% at the North and South sites, while very little change was observed in the NO<sub>2</sub> levels at the East site over the same period of air monitoring. Ambient ozone levels appeared to be reduced slightly over the period of monitoring, while no discernible changes were observed in the TSP and PM<sub>10</sub> ambient levels.



**TABLE 5.2-1. SUMMARY OF MONITORING PROGRAM PARAMETERS  
 NYSEG MILLIKEN STATION AMBIENT MONITORING PROGRAM**

Location	Monitored Parameters	Elevation (AGL)
North Site* (Nut Ridge Road)	Sulfur Dioxide (SO <sub>2</sub> )	5 meters
East Site (Lake Ridge Road)	Nitrogen Oxides (NO, NO <sub>2</sub> , NO <sub>x</sub> )	5 meters
South Site (Algerine Road)	Total Suspended (TSP) and Fine Particulates (PM <sub>10</sub> )	5 meters
	Trace Metals**	5 meters
	Wind Speed	10 meters
	Wind Direction	10 meters
	Sigma Theta	10 meters
	Temperature	10 meters

North Site also monitored ozone (O<sub>3</sub>) at 5 meters.

\*\* Trace Metals: arsenic, cadmium, chromium (total) and nickel sampled periodically throughout the 4-year monitoring period.

Location	Monitored Parameters	Elevation (AGL)
Central Meteorological Site	Wind Speed	0, 50, 100 meters
	Wind Direction	10, 50, 100 meters
	Vertical Wind Speed	10, 50, 100 meters
	Sigma Theta	10, 50, 100 meters
	Sigma W	10, 50, 100 meters
	Temperature	2 meters
	Temperature Difference	2-10 meters 10-50 meters 10-100 meters
	Solar Radiation	ground
	Net Radiation	ground
Solar Site	Wind Speed	50,100,150,200,250,300,350,400 meters
	Wind Direction	
	Sigma Theta	
	Vertical Wind Speeds	
	Sigma W	

**TABLE 5.2-2  
MONITORING EQUIPMENT FOR THE MILLIKEN STATION AMBIENT MONITORING  
PROGRAM**

<b>Parameter/Function</b>	<b>Instrument</b>
Sulfur Dioxide (SO <sub>2</sub> )	TECO 43
Nitrogen Oxides (NO <sub>x</sub> )	TECO 14B/E TECO 42
Ozone (O <sub>3</sub> )	TECO 49
Particulate (TSP/PM <sub>10</sub> )	GMW/Model 1200 Inlet
Wind Speed	Climatronics (F-460)
Wind Direction	Climatronics (F-460)
Vertical Wind Speed	R.M. Young/Climatronics (101284)
Temperature/Delta Temp.	Climatronics
Sigma Theta	Odessa DSM 3260
Sigma W	Odessa DSM 3260
Solar Radiation	Eppley (848)
Net Radiation	REBS (Q6)
Data Collectors (4)	Odessa DSM 3260
Telemetry	Hayes 300 Smartmodem
Calibration Tracking (2)	Monitor Labs 8500 Calibrator with timer and valve ray
Strip Chart Recorders	Esterline Angus MS412C and EA601C
Multipoint Calibrations and bi-weekly Precision and Level 1 Checks	ENSR Portable Gas Dilution Calibration System TECO 49 Ozone Transfer Standard

**TABLE 5.2-3  
NEW YORK STATE ELECTRIC & GAS T-TEST RESULTS ( NO<sub>2</sub> AND O<sub>3</sub>)**

<b>Site (Parameter)</b>	<b>Period</b>	<b>Average Concentrations (ppb)</b>	<b>T Values*</b>
North (NO <sub>2</sub> )	6/20/95- 12/31/96	5.246	16.14
	2/1/93-12/10/94	6.159	
South (NO <sub>2</sub> )	6/20/95- 12/31/96	5.531	16.91
	2/1/93-12/10/94	6.542	
East ( NO <sub>2</sub> )	6/20/95- 12/31/96	5.697	0.018
	2/1/93-12/10/94	5.698	
North (O <sub>3</sub> )	6/20/95- 12/31/96	32.370	2.726
	2/1/93-12/10/94	32.831	

Confidence Levels (n = ∞):\*

T<sup>1</sup> (.9995) = 3.291

T<sup>1</sup> (.95) = 1.645

T<sup>1</sup> (.60) = 0.253

\* If T is greater than T<sup>1</sup>, the change is significant,

FIGURE 5.2-3

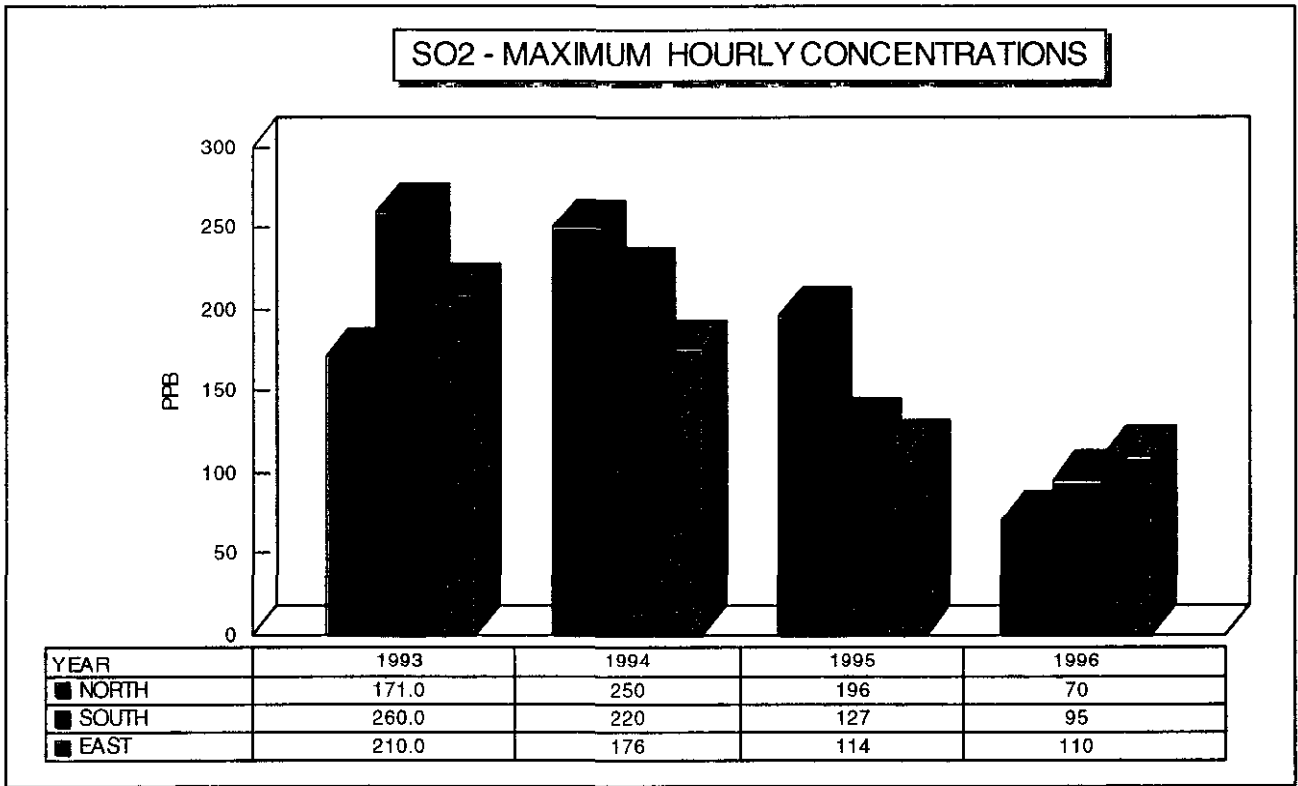
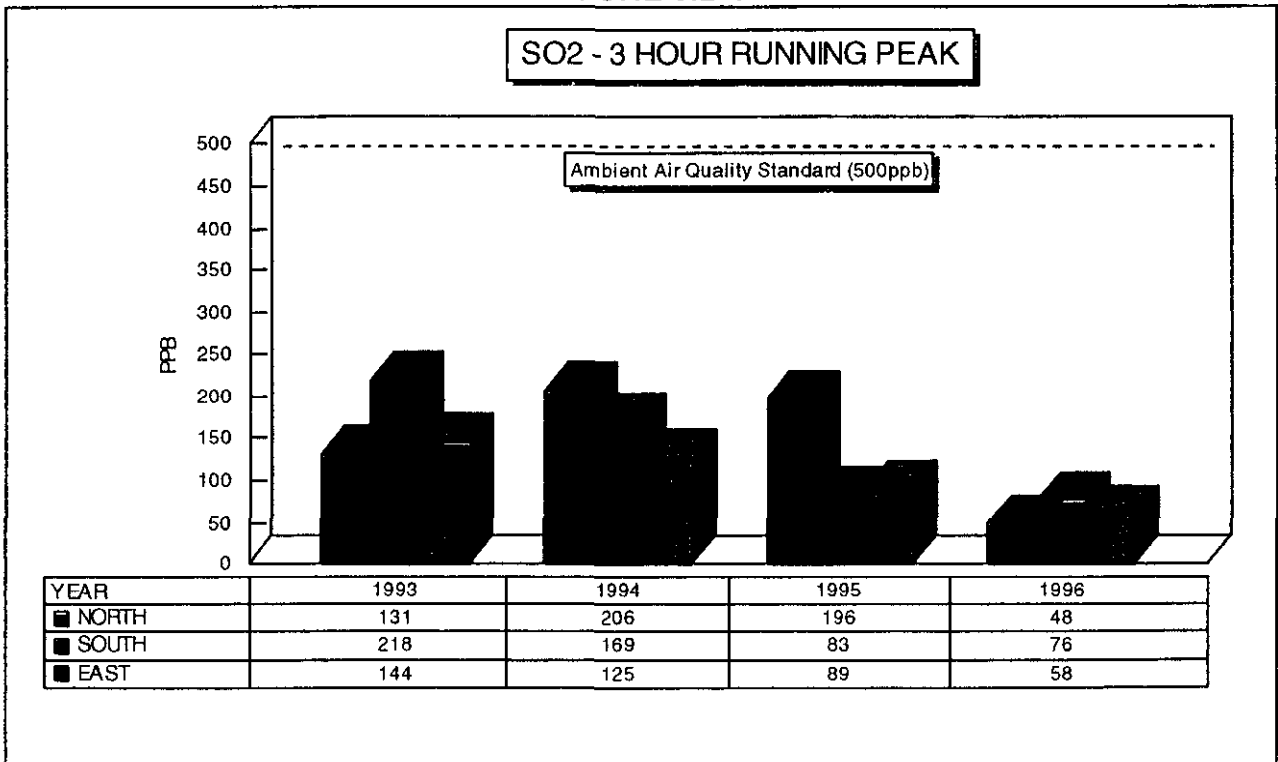
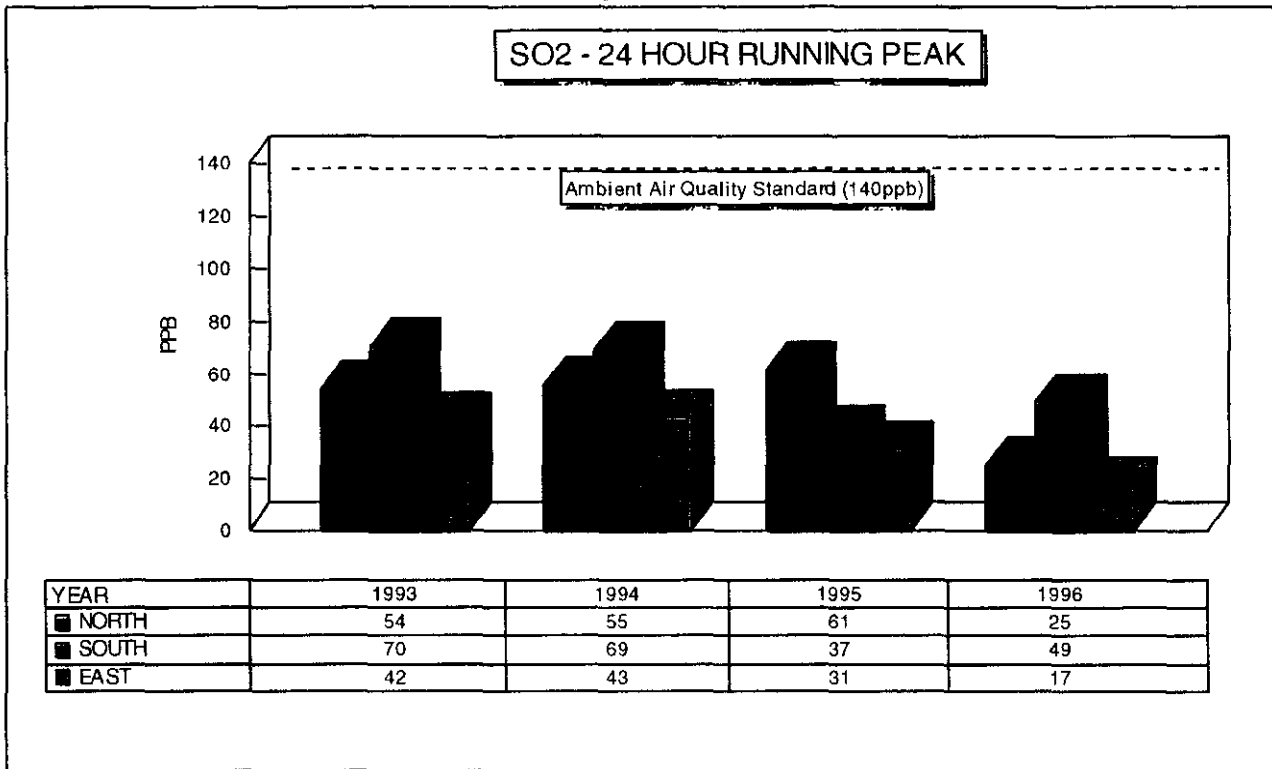


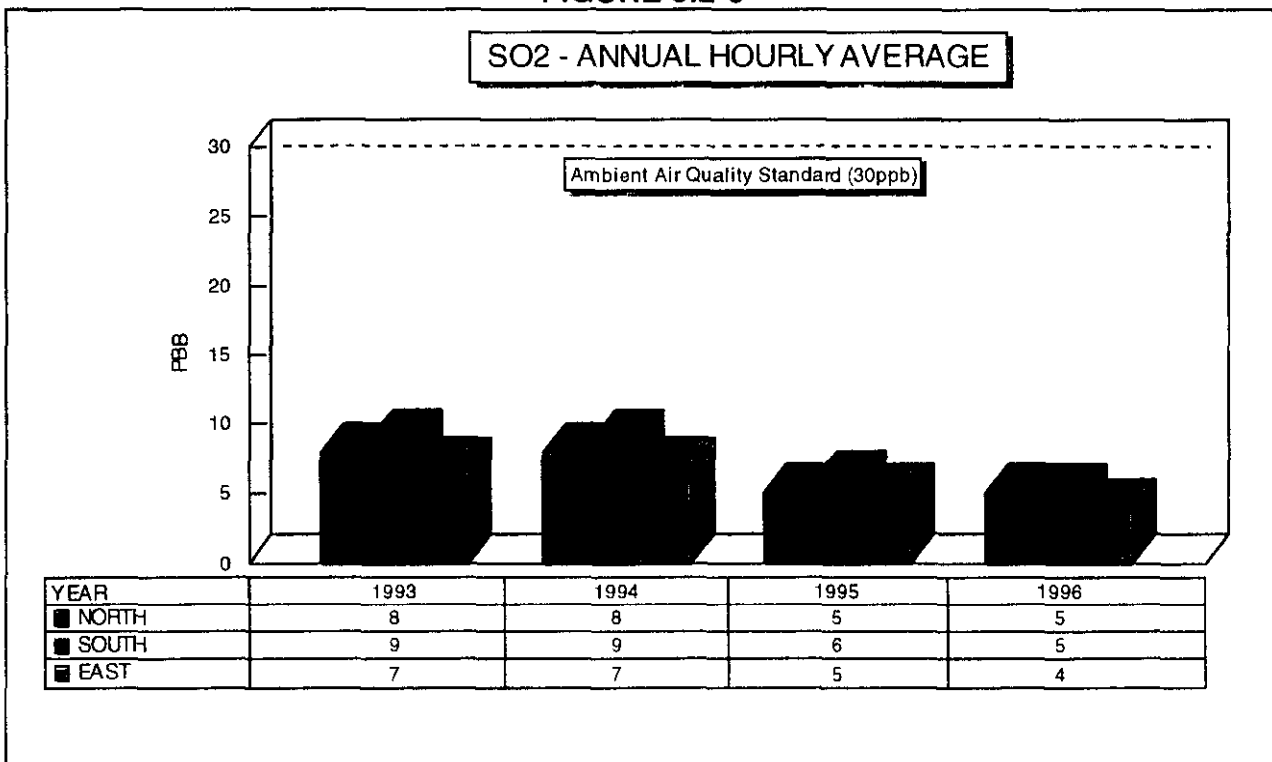
FIGURE 5.2-4



**FIGURE 5.2-5**



**FIGURE 5.2-6**



**FIGURE 5.2-7  
DIURNAL VARIATION (SO<sub>2</sub>) PLOTS**

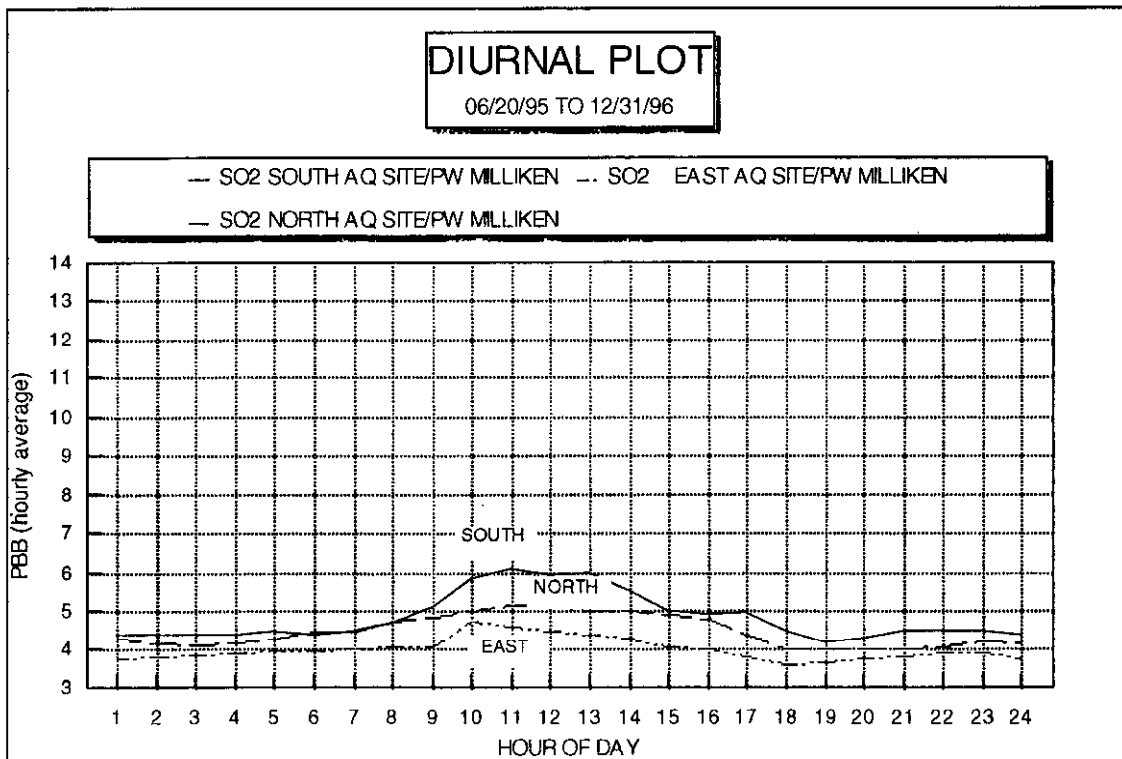
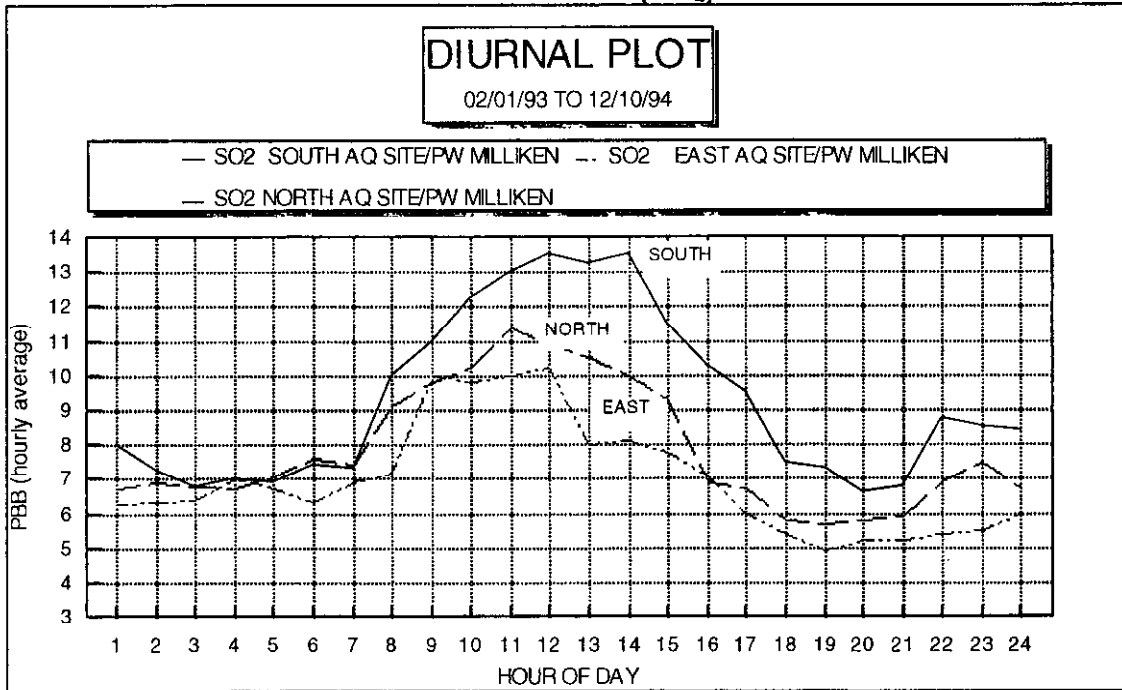


FIGURE 5.2-8

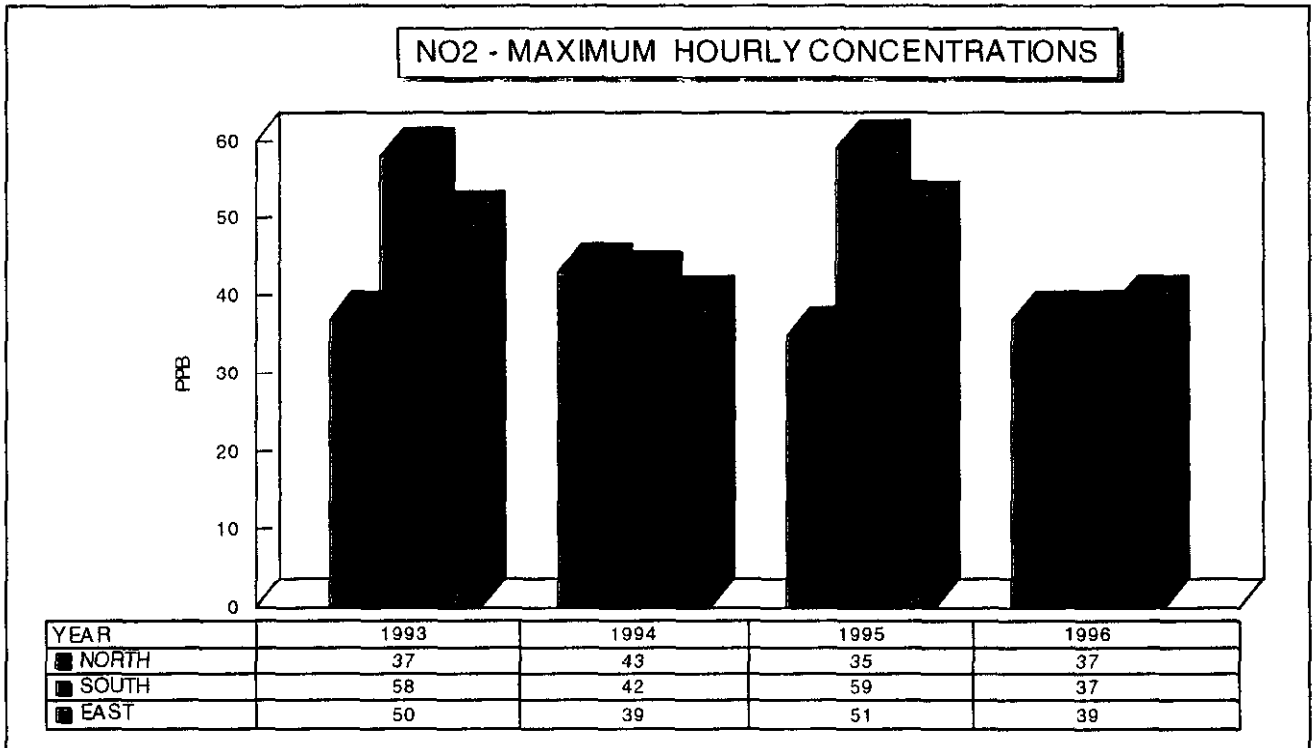
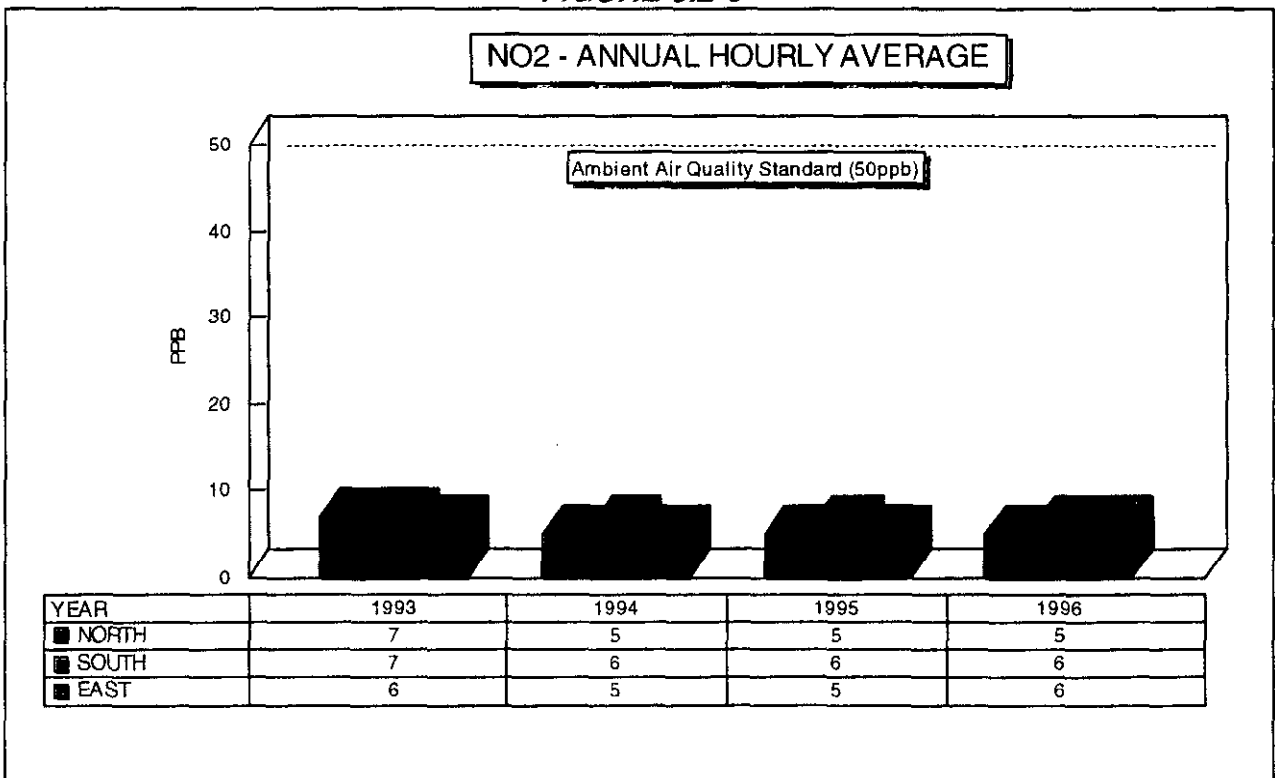
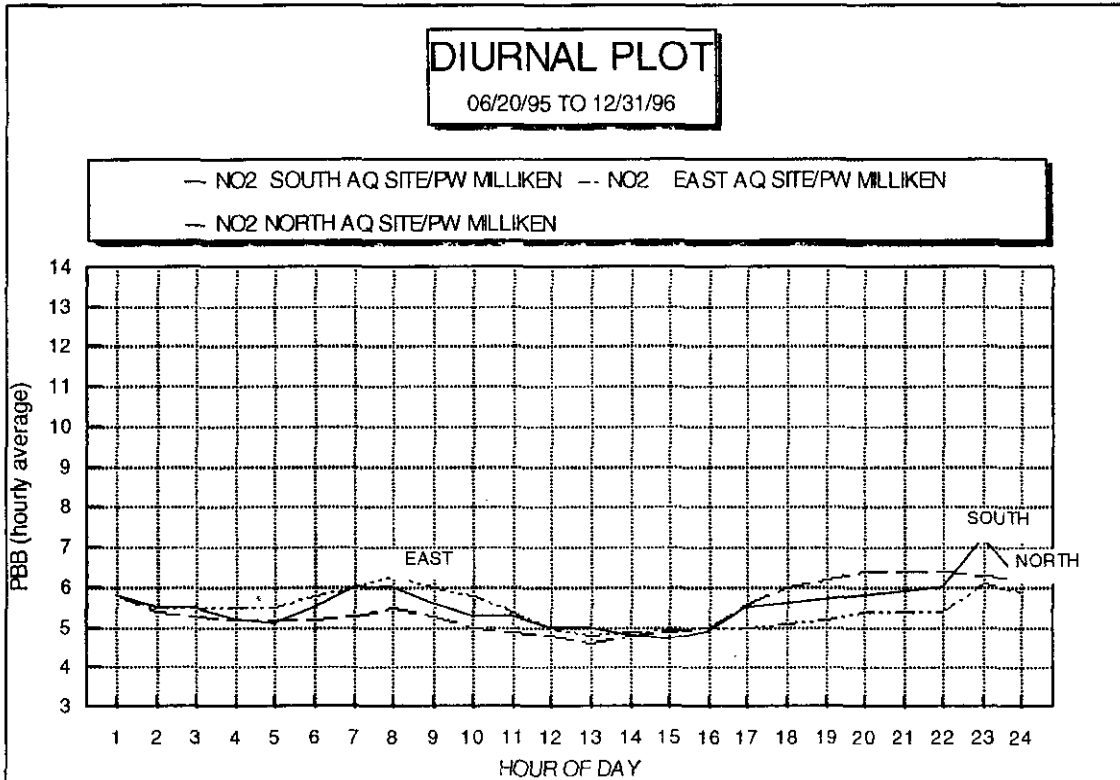
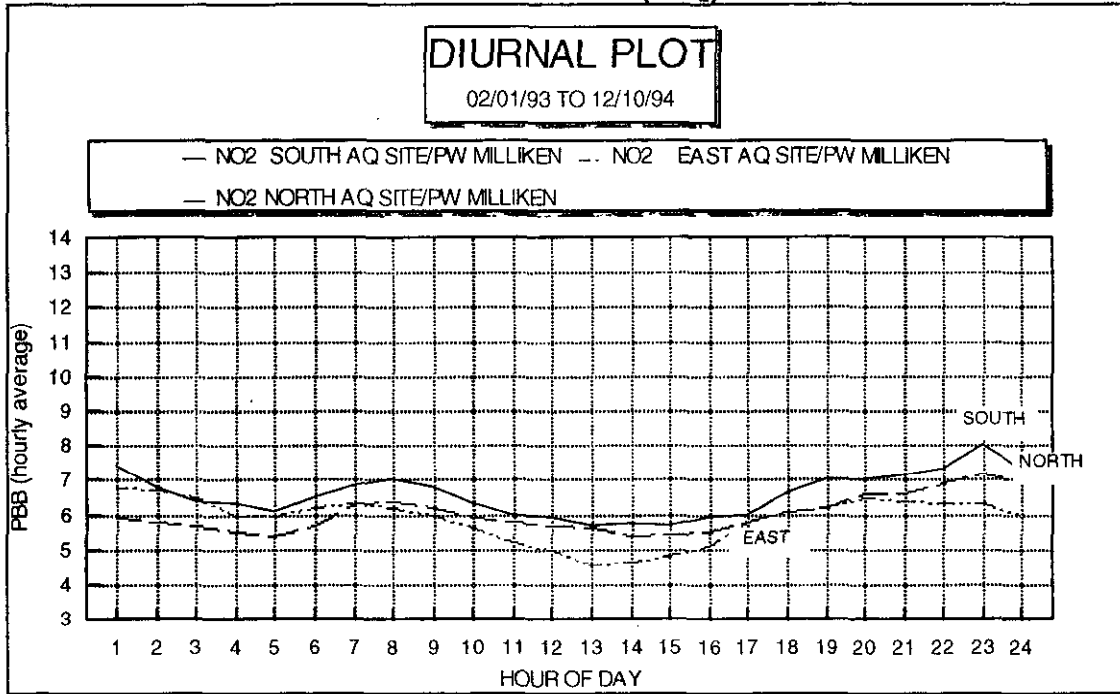


FIGURE 5.2-9

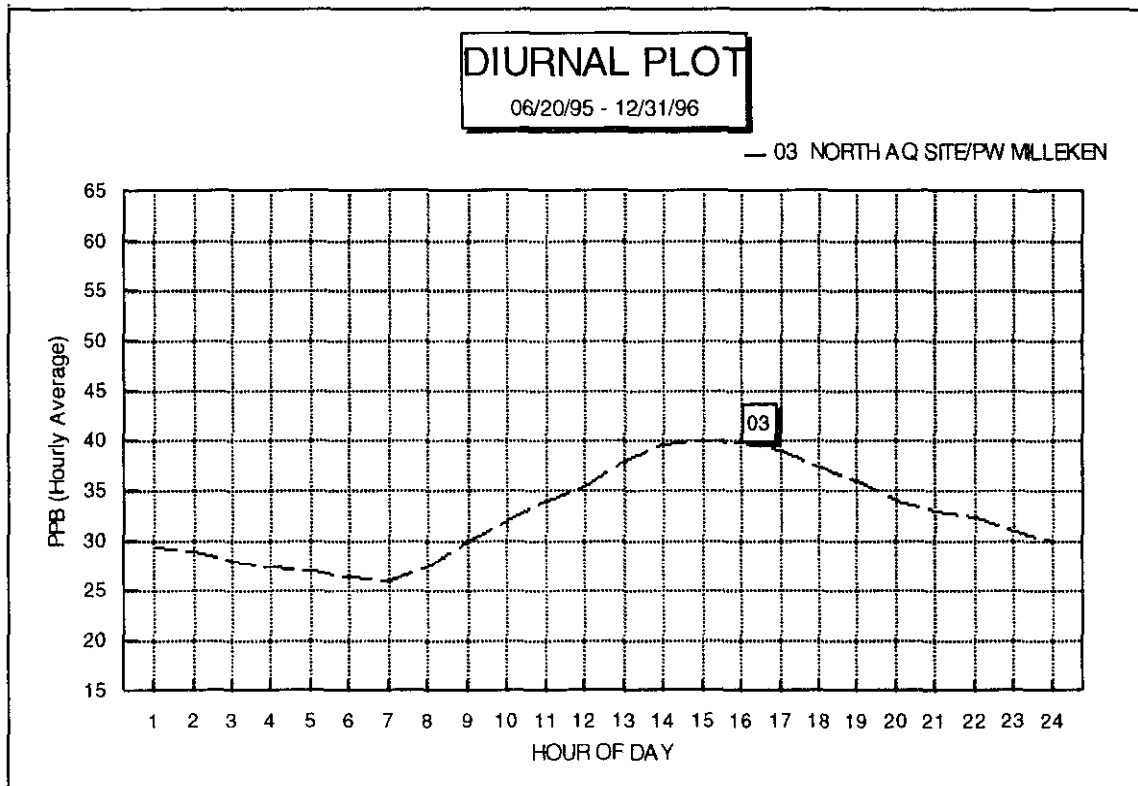
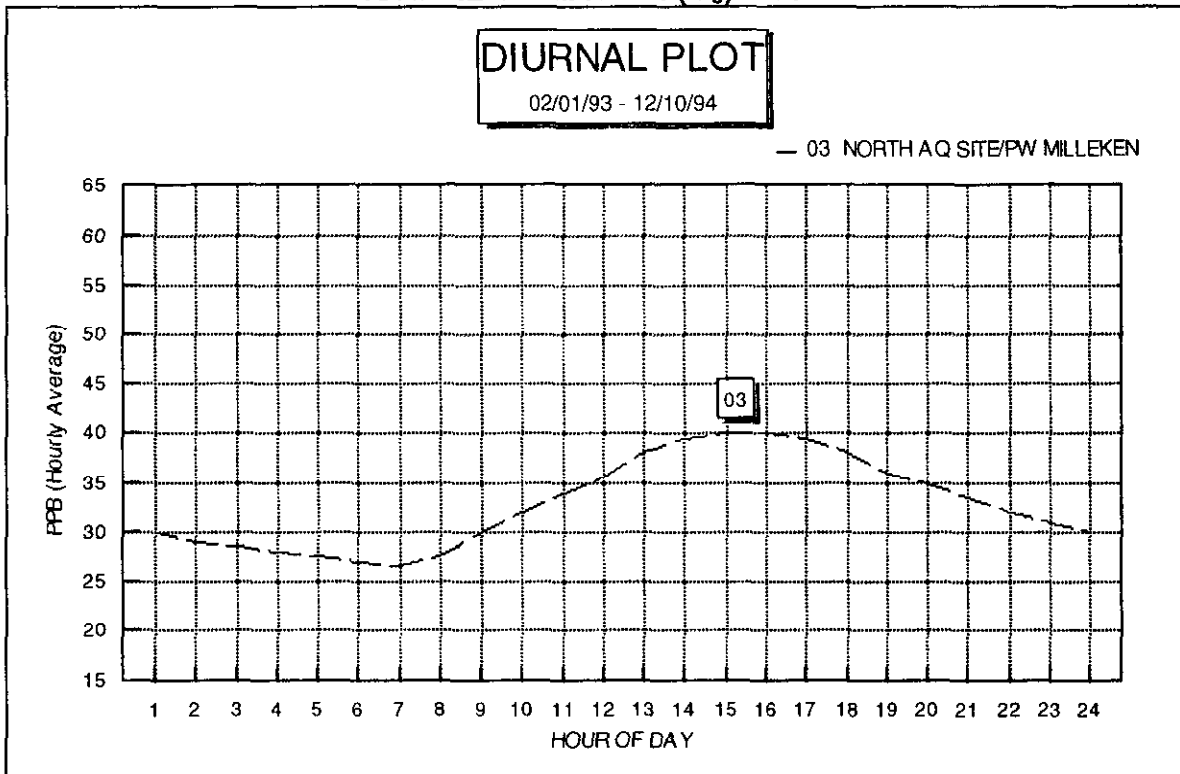


**FIGURE 5.2-10  
DIURNAL VARIATION (NO<sub>2</sub>) PLOTS**





**FIGURE 5.2-11  
DIURNAL VARIATION (O<sub>3</sub>) PLOTS**



### **5.2.3 WATER QUALITY**

This section summarizes the operation of the various waste water treatment and sampling programs at Milliken Station. The station operates a Coal Pile Runoff and Maintenance Cleaning Waste Water Treatment Facility which discharges into the Process Waste Reclamation Facility (PWRF). The PWRF treated water is either reused as process water in the FGD system or is discharged via the circulating water discharge to Cayuga Lake. The FGD system has its own waste water treatment system which treats the brine concentrator feed water for solids and heavy metals. The treated brine feedwater is then concentrated in the brine concentrator which produces a 35% calcium chloride brine and a distillate.

#### **WASTE WATER TREATMENT**

Major station elements that generate wastewater include cooling water systems, boiler blowdown, demineralizer backwashes, sump pump discharges and sanitary sewage. The majority of wastewater from Milliken (214 MGD) is non-contact cooling water, discharged to Cayuga Lake in accordance with NYSEG's existing State Pollution Discharge Elimination System Permit (SPDES #0001333). The remainder of the wastewater stream (2.27 MGD) is composed of regeneration wastes, boiler blowdown, sanitary wastes, area washes, yard and roof drainage, and drainage from the coal storage pile and ash landfill. Sanitary waste is discharged through a separate system which includes a septic tank, sand filter and chlorinator.

All facility wastewater discharges, including the effluent from the coal pile runoff and maintenance cleaning wastewater treatment system receives final treatment via the PWRF system which uses API separators and gravity sand filtration prior to discharge. Solids from the coal pile basin, facility lift station, API separator and waste water treatment are neutralized, clarified and dewatered. Chemical cleaning of the boilers is performed on a six-year cycle. During these times, chemical cleaning wastewater is transported off-site for treatment prior to disposal by a licensed vendor.

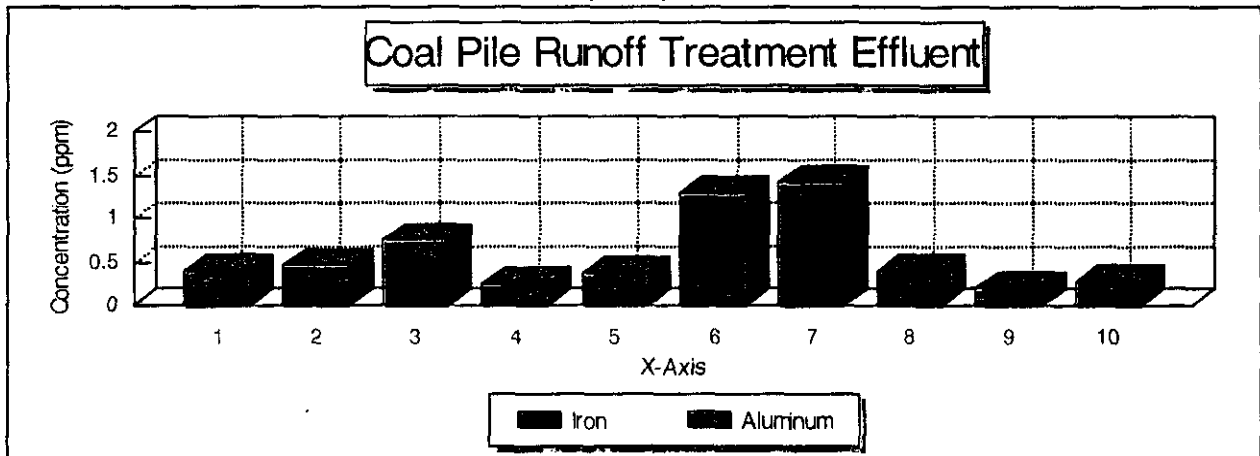
Coal-pile runoff and maintenance cleaning wastewater are treated and discharged to PWRF system in accordance with NYSEG's SPDES permit (#0001333). All discharges were in compliance and were listed by week in each quarterly report in tables similar to Table 5.2-4. Process water from plant drains, yard and roof drains and accessory equipment cooling is collected and treated in the Process Water Reclamation Facility (PWRF) and discharged to Cayuga Lake in accordance with NYSEG's SPDES permit (#0001333). PWRF discharges were in compliance with the discharge permit and with data summarized by week in each quarterly report in tables similar to table 5.2-5.

Leachate and surface water runoff from Milliken landfill are currently collected in a 3.8 million gallon sedimentation basin designed to hold runoff from a 10-year, 24-hour storm event. After sedimentation, water is discharged to Cayuga Lake in accordance with the

landfill's SPDES permit (#0108553). When required to meet permit limits, the basin effluent can be routed to a bottom ash filter at the basin discharge for additional solids removal. The discharge water quality complied with all discharge permit notations and is summarized in each quarterly report in tables similar to table 5.2-6.

During 1995, the coal pile runoff and maintenance cleaning wastewater treatment facility had eight discharges. Each of the discharges complied with the notations of the SPDES Permit. Performance of the coal pile treatment system is relatively consistent for most of the metals. Iron and aluminum have the largest variances (and are illustrated in figure 5.2-12) which is due in part to the varying concentrations of these metals in air heater washes and coal pile runoff. The batch treatment of these wastes is also a factor in the iron and aluminum variability.

FIGURE 5.2-12



**TABLE 5.2-4 (TYPICAL)  
MILLIKEN STATION  
COAL PILE RUNOFF AND MAINTENANCE CLEANING WATER EFFLUENT  
THIRD QUARTER 1995**

Parameter	Units	Week 1	Week 2	Week 3	Week 4	Week 5	Week 6	Week 7	Week 8	Week 9	Week 10	Week 11	Week 12	Week 13
Aluminum, total	mg/l	NR	NR	NR	1.36	NR	NR	NR	1.44	NR	NR	NR	NR	NR
Arsenic, total	mg/l	NR	NR	NR	<0.002	NR	NR	NR	<0.002	NR	NR	NR	NR	NR
Chromium, total	mg/l	NR	NR	NR	<0.01	NR	NR	NR	<0.01	NR	NR	NR	NR	NR
Copper, total	mg/l	NR	NR	NR	0.021	NR	NR	NR	0.013	NR	NR	NR	NR	NR
Iron, total	mg/l	NR	NR	NR	0.16	NR	NR	NR	0.17	NR	NR	NR	NR	NR
Lead, total	mg/l	NR	NR	NR	<0.005	NR	NR	NR	<0.005	NR	NR	NR	NR	NR
Mercury, total	mg/l	NR	NR	NR	<0.0002	NR	NR	NR	<0.0002	NR	NR	NR	NR	NR
Nickel, total	mg/l	NR	NR	NR	<0.02	NR	NR	NR	<0.02	NR	NR	NR	NR	NR
Zinc, total	mg/l	NR	NR	NR	<0.01	NR	NR	NR	<0.01	NR	NR	NR	NR	NR
pH	S.U.	NR	NR	NR	7.8	NR	NR	NR	7.9	NR	NR	NR	NR	NR
Flow average	gal/day	60,000			50,000			0						

NR - Denotes system is not running

**TABLE 5.2-5 (TYPICAL)  
MILLIKEN STATION  
PROCESS WATER RECLAMATION FACILITY EFFLUENT  
THIRD QUARTER 1995**

Parameter	Units	Week 1	Week 2	Week 3	Week 4	Week 5	Week 6	Week 7	Week 8	Week 9	Week 10	Week 11	Week 12	Week 13
TISS	mg/l	<4.0	5.1	<4.0	<4.0	<4.0	<4.0	<4.0	<4.0	<4.0	<4.0	<4.0	4.0	<4.0
Oil and Grease	mg/l	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0
Aluminum, Total	mg/l	0.32	0.33	0.37	0.32	0.33	0.30	0.30	0.31	0.31	0.23	0.30	0.37	0.33
pH	S.U.	8.2	8.25	8.05	8.0	8.0	8.1	8.19	8.0	7.9	8.3	8.1	8.1	7.9
Flow average	gal/day	4,083,226												
Chlorine, residual	mg/l	0.2												
		4,814,419												
		4,042,333												
		0.4												

**TABLE 5.2-6 (TYPICAL)  
MILLIKEN ASH DISPOSAL FACILITY  
SEDIMENTATION POND EFFLUENT**

**SAMPLE COLLECTION DATE: 8/30-31/95**

Parameter	Results	Units
Flow	135,184	gal/day
Aluminum, total	0.18	mg/l
Arsenic, total	0.11	mg/l
Cadmium, recoverable	<0.005	mg/l
Iron, total	0,011	mg/l
Manganese, total	<0.010	mg/l
Mercury, total	<0.0002	mg/l
Nickel, recoverable	<0.020	mg/l
Oil and Grease	<5.0	mg/l
Total Suspended Solids	<4.0	mg/l
Zinc, recoverable	<0.010	mg/l
pH	8.6	S.U.

\* Annual sampling requirement - not sampled during this collection

**STORMWATER RUNOFF**

The U.S. EPA has issued storm water management regulations (40 CFR 122-124) which establish National Pollutant Discharge Elimination System (NPDES) permit application requirements for storm water discharges associated with industrial activity. These regulations are enforced by the NYSDEC through the SPDES permitting process. The NYSDEC has issued, through the Division of Water Technical and Operations Guidance Series, the Storm Water Management Guidelines for New Development. This document provides procedures for development to ensure that runoff during and after construction is not substantially altered from pre-development conditions. Since the MCCTD project disturbed greater than five acres of land, NYSEG applied for a Storm Water SPDES Permit.

A construction plan was submitted to the NYSDEC which specified erosion control measures to be used during construction. The objective of the plan included:

- segregation of rainfall runoff flowing over disturbed areas from runoff flowing over areas not disturbed by construction activities,
- collection of runoff from disturbed areas in a controlled manner,
- management of runoff and rainfall that collects in excavation sites,

- minimization of sediment loading of runoff from disturbed areas and water pumped from excavations; to ensure that effluent from those areas conforms with New York State Guidelines for Urban Erosion and Sediment Control.

During 1995 all permanent stormwater control systems were installed and functional. The stormwater control systems were designed to ensure that the limestone storage sedimentation basin receives all run off from the limestone stock pile. The water collected in the limestone sedimentation basin is then pumped to the FGD system where it is used as make up water. Stormwater from the FGD project was monitored in accordance with the SPDES Permit (#0001333).

The FGD sedimentation basin which was installed during construction continues to be used during operation. Runoff from the FGD area is conveyed to this sedimentation basin. The water discharges through a stand pipe where it discharges to Cayuga Lake.

## **GROUNDWATER MONITORING**

NYSEG maintains seven groundwater monitoring wells upgradient of the ash disposal facility, ten wells downgradient of the facility, and five wells within the boundaries of the ash disposal facility for the purpose of monitoring groundwater quality in accordance with the provisions of the Solid Waste Management Facility (SMW) operating permit and Milliken SPDES permits. The NYSDEC has modified the landfill's permits to allow disposal of FGD system wastewater treatment sludge and unmarketable by-products. Fluoride was added to the existing monitoring program for baseline monitoring. Table 5.2-7 lists the groundwater monitoring parameters.

Groundwater monitoring continued throughout the demonstration as specified in the SPDES and 360 Permits for the Solid Waste Disposal Area. Groundwater monitoring data are presented in detail in each of the quarterly environmental monitoring reports, which are available upon request from NYSEG.

Milliken Ash is divided into two sections; a closed unit which operated until 1984 and an active post-1984 section. The pre-1984 section was constructed using native soils existing at the site as a liner while the active section utilizes a modified composite system liner system with leachate collection.

The wells monitoring the groundwater downgradient of the operational, post-1984 section of the landfill indicate no groundwater contamination problems occurring due to the operation of that section of the landfill. Sulfate concentrations are at background levels and apparently no leachate is migrating from the active sections of the facility. This is an important factor since off-spec. FGD byproducts and waste water treatment sludges are landfilled in this area.

**TABLE 5.2-7  
SOLID WASTE MANAGEMENT FACILITY  
GROUNDWATER MONITORING**

<b>Groundwater Parameters</b>	<b>Form</b>	<b>Units</b>	<b>Frequency*</b>
aluminum	total & dissolved	mg/l	quarterly
alkalinity		mg/l	quarterly
arsenic	total & dissolved	mg/l	quarterly
cadmium	total & dissolved	mg/l	quarterly
iron	total & dissolved	mg/l	quarterly
hardness		mg/l	quarterly
mercury	total & dissolved	mg/l	quarterly
magnesium	total & dissolved	mg/l	quarterly
manganese	total & dissolved	mg/l	quarterly
lead	total & dissolved	mg/l	quarterly
pH		mg/l	quarterly
selenium	total & dissolved	mg/l	quarterly
sulfate		mg/l	quarterly
dis. solids	total	mg/l	quarterly
turbidity		mg/l	quarterly
zinc	total & dissolved	mg/l	quarterly
fluoride		mg/l	quarterly

Sulfate appears to be the best parameter to monitor the impact of an ash landfill on ground water quality. It occurs at relatively high concentration in the leachate and is not prone to reactions involving ion exchange or significantly retarded by a sod matrix. The total dissolved solids and metal data with the possible exception of selenium, do not provide any clear trends and most of the exceedances of these parameters reflect the irregular distribution of these constituents in the native sod and ground water at Milliken Ash Site.

The sulfate data clearly indicate that leachate from the soil-lined, pre-1984 section continues to impact the water quality immediately down gradient of that section. However, wells further down gradient from the unlined section have sulfate concentrations that are at or below background levels for the site. The plume appears to be in steady-state or is receding as a result of remedial measures completed at Milliken Ash in recent years. The terrain conductivity survey data from 1993 which was submitted to NYSDEC in 1994, confirmed that the plume is at steady-state or is receding. Preliminary results of the survey conducted in 1995 indicate a continued improvement in ground water quality down gradient of the older, closed section of the landfill. Wells will continue to be monitored at the site for any changes in ground water quality



## 5.2.4 SOLID WASTE

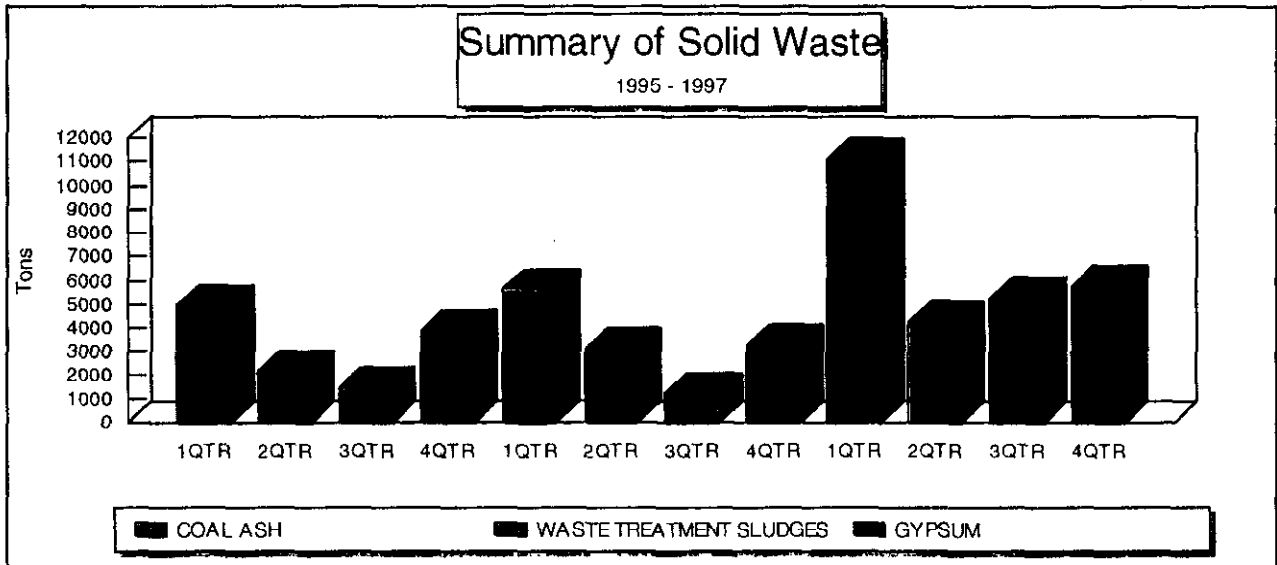
Milliken Station operates a solid waste disposal area east of the plant which encompasses approximately 41 acres. The disposal area began operation in 1978 and accepted primarily combustion byproducts from Milliken Station which included fly ash, bottom ash and pyrite rejects. In addition the facility received sludges and sediments from maintenance cleaning wastes from Milliken Station.

Extensions to the landfill were made in 1978, 1979, 1982, 1984, 1986 and 1990. Currently only the 1986 and 1990 extensions are active. The active portion of the landfill utilizes a modified composite liner consisting of a low permeability soil liner, a leak detection system, a synthetic liner, and a leachate collection system. The closed portions of the waste disposal area utilized a low permeability soil liner design meeting the effective regulatory requirements with leachate collection and a low permeability cap covered by top soil as a final cover.

The 1984, 1986 and 1990 extensions are hydraulically and operationally separate from the previous extensions to the waste disposal area.

Solid waste generation during 1995 - 1996 is depicted on figure 5.2-13. Fly ash disposal is initially high due to the tuning of the LNCFS-3 burners. Fly ash disposal dropped off during the course of the year as optimization of the burners was finalized. During the second quarter of 1995 gypsum disposal was due to the problems experienced with the centrifuges. However, during the fourth quarter the jump in gypsum disposal was primarily market driven as NYSEG negotiated a final purchase agreement with a wall board manufacturer. Sludge disposal increased as a result of starting up the FGD brine feed water treatment and both FGD modules becoming operational.

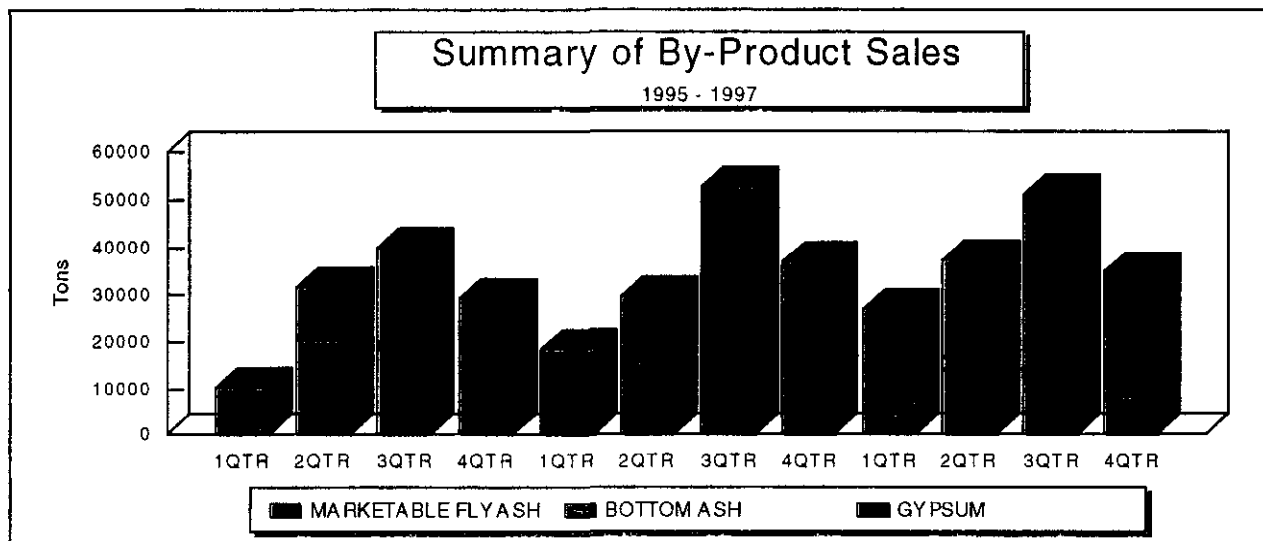
FIGURE 5.2-13



The sales of fly ash reflected the tuning of the new burners system in which much of the ash exceeded the maximum percentage (4%) of unburned carbon. As the operating experience increased with the burner system, so did the salability of flyash. The gypsum sales followed increased production due to the start-up of the Unit 1 FGD module in June 1995 and the development of contractual commitments for the gypsum. Since 100% of the bottom ash is sold as anti-skid material in the winter months, sales of bottom ash are directly related to production at the Station. Bottom ash is stored on site until the winter season when it is sold to local municipalities. The bottom ash and some gypsum were stockpiled at the solid waste disposal area while the fly ash was immediately sold to be used in concrete mixes. Sales of these combustion by-products have helped to prolong the life of the solid waste disposal facility as well as generating a revenue stream for the company.

Marketing activity during 1995 - 1996 is depicted on figure 5.2-14.

FIGURE 5.2-14



### 5.2.5 NOISE

The permit issued by the NYSDEC to allow construction of the Milliken CCTD project had three conditions specific to noise attenuation which included the following terms:

- No increase in residual ( $L_{90}$ ) noise levels greater than 3 A-weighted decibels is permitted at the following receptor noise monitoring stations:
  - near the closest residence on Milliken Station Road extension, located approximately 1,000 feet south of the main facility building. This residence is situated between the Conrail railroad tracks and the east shore of Cayuga Lake.
  - near the closest residence north of Milliken at the end of Cuddeback Road, approximately 7,000 feet northwest of the facility.

- near the closest residence east of Milliken, 34 Milliken Station Road, approximately 5,400 feet east northeast of the facility.
- adjacent to the closest residence on the west shore of Cayuga Lake located directly across from Milliken, approximately 9,000 feet west southwest of the facility.
- at the intersection of Lake and Cuddeback Roads at the end of Algerine Road
- at the intersection of Algerine and Ludlow Roads.
- The permittee will make every reasonable effort to assure that no sounds of tonal character (e.g. hums, whines, squeals, or whistles) are clearly perceptible at annoying magnitudes at the seven receptor locations from any plant modifications that are the subject of this permit.
- Achievement of the plant design goals with respect to noise must be verified by means of a post modification noise performance test. The test will consist of measurements, per the DEIS section 3.5.5 existing ambient survey at the seven sensitive receptor locations. The verification measurements must be performed while the plant is operating at full output. The results of these tests must be sent to the NYSDEC.

Noise measurements were taken during the periods of July 20-23, 1992 and August 28-30, 1995 for baseline and project operational conditions, respectively. Measurement results for both of these periods showed that only at one location was the noise from Milliken readily discernible during both daytime and nighttime periods. At the other six receptor locations, noise was generally either not perceptible or barely perceptible. None of the seven receptor locations had noise that could be considered "of a tonal character ...clearly perceptible at annoying magnitudes." An analysis of the changes in residual ( $L_{90}$ ) noise levels at the seven monitoring stations indicates that the project operational noise did not exceed the allowable 3 dBA increase value. However, the project operational measurement program (August 28-30, 1995) was conducted during a period of significantly greater insect noise (i.e. crickets, cicadas & locusts) than existed during the baseline (July 20-23, 1992) measurements. This non-Milliken source noise was corrected for determining ultimate residual noise levels.

The project operational measurements and observations showed that any increase in residual noise levels due to the Milliken CCTD project occurred only at one monitoring location, where the increase was 1 dBA. No instances of annoying tonal noise were identified. The CCTD project has met the environmental noise criteria of the special permit conditions. Details of the noise measurement program can be found in the report entitled "Ambient Noise Monitoring for the Milliken Station Clean Coal Technology Demonstration Project" available from NYSEG upon request.

## 5.2.6 CHARACTERIZATION OF ANY UNREGULATED SUBSTANCES

### LIQUIDS

The only new liquid substance generated as a result of this project is the calcium chloride brine. A request for determination of beneficial use was granted by the NYSDEC for direct application of the brine as a road de-icer and dust suppressant. The concentrated brine results from the FGD blowdown which is treated for solids, heavy metals and then concentrated in an evaporator. Table 5.2-8 provides the anticipated chemical constituents of the calcium chloride salt. Since the brine concentrator has had operational difficulties, the actual characteristics of the calcium chloride brine have not been determined.

**TABLE 5.2-8  
EXPECTED CHEMICAL COMPOSITION OF CALCIUM CHLORIDE SALT**

<b>Chemical Composition</b>	<b>Percentage by Weight</b>
Calcium Chloride (CaCl <sub>2</sub> )	57
Magnesium Chloride (MgCl <sub>2</sub> )	28
Sodium Chloride (NaCl)	8
Other alkali chlorides	2
Inerts	5

### SOLIDS

NYSEG has been involved in an extensive testing and research program to evaluate FGD produced gypsum and its market potential. NYSEG conducted forced oxidation FGD testing at the Electric Power Research Institute (EPRI) High Sulfur Test Center (HSTC) located at NYSEG's Kintigh Station. ORTECH International, recognized in the wallboard industry as a reputable testing firm conducted a literature survey and preliminary market analysis as well as analyzing gypsum produced at the HSTC. Results of ORTECH's literature survey and NYSEG's inspection of European FGD systems have shown that gypsum has the highest market potential as a salable by-product as a raw material for the production of wallboard and cement. This information was used to generate an EPRI Report, "The Gypsum Industry and Flue Gas Desulfurization (FGD) Gypsum Utilization: A Utility Guide" which was published in February 1994 (EPRI Report TR-103652).

Gypsum properties will be similar to gypsum samples generated in 1991 at the HSTC. Those samples were produced from tests simulating forced oxidation of the Kintigh

Station FGD system. Physical characteristics of the gypsum produced at Kintigh are listed in Table 5.2-9.

Chemical characteristics of various synthetically produced gypsum by-products and natural gypsum are listed in Table 5.2-10. Market evaluations of gypsum have indicated a high purity of CaSO<sub>4</sub>. The gypsum also meets wall board specification requirements which include chlorides, carbonate and moisture.

**TABLE 5.2-9  
TYPICAL GYPSUM PROPERTIES\***

PROPERTY	EXPECTED VALUE
pH	8.0 - 8.2
MOISTURE CONTENT (G MOISTURE/100 G DRY SOLID)	7.4 - 8.5
PERMEABILITY COEFFICIENT (CM/SEC)	0.000080 - 0.00010
UNCONFINED COMPRESSIVE STRENGTH (PSI)	11
GYPSUM (%)	95.5 - 97.4
CACO <sub>3</sub> (5)	1.0 - 3.8

\* BASED ON RESULTS FROM KINTIGH STATION SIMULATIONS.

**GASEOUS**

No unregulated gaseous materials will be produced as a result of the Milliken Clean Coal Technology Demonstration Project.

**TABLE 5.2-10**

**ANALYSIS OF VARIOUS BY-PRODUCTS AND NATURALLY OCCURRING GYPSUM  
MAJOR ELEMENTS (WT%)**

	EUROPEAN BY- PRODUCT GYPSYM	SYNTHETIC GYPSUM		U.S. UTILITY BY- PRODUCT	PILOT PLANT BY- PRODUCT	NATURALLY OCCURING	
		1	2			1	2
<b>MAJOR ELEMENTS</b>							
CaO	30 - 32.6	32.05	34.17	32.48	33.93	31.45	32.05
SO <sub>3</sub>	42 - 46.5	45.53	43.64	42.41	43.69	43.78	43.60
MgO	0.01 - 0.06	9.06	0.07	0.05	0.28	0.22	1.12
SiO	-	0.01	0.03	-	-	0.04	0.36
Al <sub>2</sub> O <sub>3</sub>	0.1 - 0.50	0.05	0.13	0.02	0.05	0.55	0.22
Fe <sub>2</sub> O <sub>3</sub>	0.01 - 0.13	0.07	0.09	0.06	0.15	0.24	0.07
SiO <sub>2</sub>	0.17 - 0.65	1.35	0.75	0.58	<0.485	2.41	0.66
MnO	-	<0.01	0.01	-	-	0.03	<0.01
P <sub>2</sub> O <sub>5</sub>	-	<0.01	<0.01	<0.017	<0.019	0.01	<0.01
K <sub>2</sub> O	0.02 - 0.12	<0.01	0.03	<0.035	<0.039	0.10	0.05
F	-	0.02	1.49	-	-	<0.01	<0.01

<b>TRACE ELEMENTS</b>							
Ag	-	-	-	<1.00	<4.0	-	-
As	<1	<5.0	<5.0	<1.00	1.41	1.4	1.0
Ba	-	-	-	1.72	1.48	-	-
Cd	<0.2	<1.0	<1.0	<1.00	0.10	<0.2	<0.02
Cr	-	3.0	10.0	1.88	3.76	5.0	<5.0
Cu	-	3.0	3.0	1.40	4.17	3.0	6.0
Hg	0.5 - 1.1	<1.0	<1.0	-	-	<0.2	<0.2
Mn	-	-	-	2.52	12.2	-	-
Pb	3 - 6	<1.0	<1.0	<1.00	0.26	2.0	2.0
Se	-	<5.0	<5.0	9.46	2.05	<0.2	<0.2
Zn	7 - 13	2.0	2.0	<1.0	16.3	6.0	4.0
F	30 - 950	475	321	678	-	<20.0	105.0
Ref.	1	2	2	3	4	2	2

have indicated a high purity of CaSO<sub>4</sub>. The gypsum also meets wall board specification requirements which include chlorides, carbonate and moisture.

**TABLE 5. 2-9  
TYPICAL GYPSUM PROPERTIES\***

PROPERTY	EXPECTED VALUE
pH	8.0 - 8.2
MOISTURE CONTENT (G MOISTURE/100 G DRY SOLID)	7.4 - 8.5
PERMEABILITY COEFFICIENT (CM/SEC)	0.000080 - 0.00010
UNCONFINED COMPRESSIVE STRENGTH (PSI)	11
GYPSUM (%)	95.5 - 97.4
CACO <sub>3</sub> (5)	1.0 - 3.8
* BASED ON RESULTS FROM KINTIGH STATION SIMULATIONS.	

## 5.2-10

**ANALYSIS OF VARIOUS BY-PRODUCTS AND NATURALLY OCCURRING GYPSUM  
MAJOR ELEMENTS (WT%)**

		SYNTHETIC GYPSUM				NATURALLY OCCURRING	
	EUROPEAN BY-PRODUCT GYPSUM	1	2	U.S. UTILITY BY-PRODUCT	PILOT PLANT BY-PRODUCT	1	2
<b>MAJOR ELEMENTS</b>							
CaO	30 - 32.6	32.05	34.17	32.48	33.93	31.45	32.05
SO <sub>3</sub>	42 - 46.5	45.53	43.64	42.41	43.69	43.78	43.60
MgO	0.01 - 0.06	9.06	0.07	0.05	0.28	0.22	1.12
SiO	-	0.01	0.03	-	-	0.04	0.36
Al <sub>2</sub> O <sub>3</sub>	0.1 - 0.50	0.05	0.13	0.02	0.05	0.55	0.22
Fe <sub>2</sub> O <sub>3</sub>	0.01 - 0.13	0.07	0.09	0.06	0.15	0.24	0.07
SiO <sub>2</sub>	0.17 - 0.65	1.35	0.75	0.58	<0.485	2.41	0.66
MnO	-	<0.01	0.01	-	-	0.03	<0.01
P <sub>2</sub> O <sub>5</sub>	-	<0.01	<0.01	<0.017	<0.019	0.01	<0.01
K <sub>2</sub> O	0.02 - 0.12	<0.01	0.03	<0.035	<0.039	0.10	0.05
F	-	0.02	1.49	-	-	<0.01	<0.01

<b>TRACE ELEMENTS</b>							
Ag	-	-	-	<1.00	<4.0	-	-
As	<1	<5.0	<5.0	<1.00	1.41	1.4	1.0
Ba	-	-	-	1.72	1.48	-	-
Cd	<0.2	<1.0	<1.0	<1.00	0.10	<0.2	<0.02
Cr	-	3.0	10.0	1.88	3.76	5.0	<5.0
Cu	-	3.0	3.0	1.40	4.17	3.0	6.0
Hg	0.5 - 1.1	<1.0	<1.0	-	-	<0.2	<0.2
Mn	-	-	-	2.52	12.2	-	-
Pb	3 - 6	<1.0	<1.0	<1.00	0.26	2.0	2.0
Se	-	<5.0	<5.0	9.46	2.05	<0.2	<0.2
Zn	7 - 13	2.0	2.0	<1.0	16.3	6.0	4.0
F	30 - 950	475	321	678	-	<20.0	105.0
Ref.	1	2	2	3	4	2	2

**GASEOUS**

No unregulated gaseous materials will be produced as a result of the Milliken Clean Coal Technology Demonstration Project.



## **5.3 CHEMICAL EMISSIONS MEASUREMENT PROGRAM AT MILLIKEN'S UNIT #2**

### **5.3.1 INTRODUCTION**

NYSEG initiated a study to establish a baseline characterization of the chemical emissions from Milliken Station's Unit 2 retrofit of the SO<sub>2</sub> and NO<sub>x</sub> control systems. The NYSEG Milliken Station has two identical 160 MW generating units and associated pollution abatement equipment. An ESP controls the particulate emissions from the boiler. No acid gas or NO<sub>x</sub> controls were in operation during the test program. Unit 2 was evaluated while it burned a 2% sulfur bituminous coal.

NYSEG retained Carnot, of Tustin, CA, to conduct the comprehensive measurement program to characterize selected trace substances potentially emitted from Unit 2. Carnot was the prime contractor for the chemical emission field test program. Roy F. Weston, Inc. (Weston), a subcontractor, performed the flue gas emission measurements at the stack location in addition to providing the site specific test protocol and assisting in solids sampling. EPRI and CONSOL, Inc. Research and Development (CONSOL) served as technical consultants. Copies of the full report of the chemical emissions study are available upon request from DOE. The report is entitled "Program Results for a Comprehensive Assessment of Chemical Emissions From New York State Electric and Gas Corporation's Milliken Station Unit 2, Lansing New York", and was prepared by Carnot in February 1995. This document discusses in detail the test program's major results and conclusions, and presents specific information on the Unit's operating conditions, sampling locations and program test schedule. It describes the sampling, analytical and data handling/reporting procedures and methods used, and presents the detailed results of the solid and liquid process stream and flue gas emission sampling. The report provides analytical techniques, trace and major element mass balances, defines quality assurance/quality control (QA/QC) information; and provides detailed descriptions of the test methods used for flue gas samples. The report's appendices include data sheets, calculations, and laboratory reports.

All sampling and analyses were conducted according to EPRI's established protocol for the PISCES test program. Results generated by the field study are considered to meet "compliance" quality standards.

The objectives of the NYSEG Milliken Station Chemical Emissions Characterization Program were:

- Characterize stack emissions of selected trace elements, target anions, and volatile and semi-volatile organics at normal full load operating conditions,
- Simultaneously measure criteria and non-criteria pollutant levels entering and exiting the power plant's electrostatic precipitator (ESP) to evaluate its effectiveness at removing various trace substances,

- Calculate a boiler/ESP material balance for selected inorganic constituents by examining their distribution levels across various input/output process streams,
- Perform mercury and chromium speciation tests at the ESP inlet and stack exhaust locations to provide additional data on selected trace substances and the ESP's effectiveness at removing them,
- Evaluate the metals wastewater treatment plant's performance at removing selected trace substances from the coal pile run-off by examining their levels in the plant's inlet and outlet effluent,
- Provide data on trace substance levels in the power plant's solid waste and wastewater discharges namely, ash, mill rejects, metals treatment plant sludge and the Process Wastewater Reclamation Facility (PWRF) outlet,
- Provide a baseline data set for Milliken Unit 2 that will be integrated into EPRI's chemical emissions database.

To achieve these objectives, a field measurement program on Milliken Unit 2 was conducted from May 4th to May 13th, 1994.

### **5.3.2 TARGET POLLUTANTS**

Representative samples from the following process streams were collected and analyzed:

#### Boiler/ESP Process Streams (triplicate samples)

- coal feed
- coal mill rejects
- bottom ash slurry
- ESP flyash
- ESP inlet flue gas
- stack flue gas

#### Wastewater Process Streams (duplicate samples)

- coal pile runoff (metals treatment plant inlet)
- metals treatment plant outlet
- process wastewater reclamation facility outlet
- metals treatment plant sludge (single samples)

Table 5.3-1 lists generic classes of substances measured on each unit process stream sampled during the Milliken chemical emissions field test. Table 5.3-2 presents the particular pollutants included in each class. These substances were selected for inclusion based on input from NYSEG, DOE and EPRI. The compounds include most of the 189 compounds listed as hazardous air pollutants under Title III of the 1990 CAAA.

### **5.3.3 SUMMARY OF MAJOR CONCLUSIONS OF CHEMICAL EMISSIONS PROGRAM**

The major conclusions drawn from the test results of chemical emissions program, are:

- The ESP was 98.9% effective at removing solid particulate matter from the flue gas stream. Stack particulate emissions averaged 0.060 lb/MMBtu. The ESP was also effective at removing solid-phase trace elements from the flue gas stream with an average removal efficiency of 98.7%.
- Stack emissions of arsenic, cadmium, lead, mercury and selenium were 10, 0.34, 5.4, 8.1 and 30 lb/10<sup>12</sup> Btu - respectively.
- Hexavalent chromium levels accounted for 5.6% of total ESP inlet chromium measured or 50 lb/10<sup>12</sup> Btu. Hexavalent chromium was not detected in the stack exhaust stream indicating that Unit 2's Cr<sup>6+</sup> existed primarily in the solid-phase and was well-controlled by the ESP with a removal efficiency of 99.9%.
- Mercury speciation results for the stack showed 86% of total mercury existing as Hg(II) and 14% existing as Hg(0). Insignificant levels of methyl Hg were found at the stack. The alternate mercury method is still being evaluated for its effectiveness in measuring mercury species; therefore, its results should be reviewed from a research perspective.
- From comparisons with solid stream sample results, Unit 2's actual stack mercury emissions level is likely bounded by the alternate mercury result of 5.1 lb/10<sup>12</sup>Btu and the EPA Method 29 value of 8.1 lb/10<sup>12</sup> Btu. A significant amount of uncertainty is associated with both sets of flue gas measurements due to their poor reproducibility; whereas, solid stream measurements of mercury are considered accurate.
- As expected, the ESP was ineffective at removing anions from the flue gas. Chloride (69,200 lb/10<sup>12</sup> Btu), fluoride (4,260 lb/10<sup>12</sup> Btu) and sulfate (4.09 x 10<sup>6</sup> lb/10<sup>12</sup> Btu) were measured at the stack.
- With the exception of phenanthrene, fluoranthene and 2-methylnaphthalene all other PAHs were measured at or below the detection limit or field blank value.
- No dioxin or furan isomer was measured at levels significantly higher than the detection limit or field blank value.

- Stack measurements of benzene at 2.2 ppb, toluene at 1.8 ppb and formaldehyde at 3.0 ppb are similar to those measured during other PISCES field investigations of coal, oil, and natural gas power-plants.
- A total ash mass balance was 98%. Ash distribution across the boiler/ESP output streams showed 0.2% exiting in the mill rejects, 13.6% leaving in the bottom ash, 85% exiting in the flyash and 1.2% being emitted from the stack.
- In general, trace and major element material balances were in the 70-130% range. Trace element (excluding mercury and selenium) partitioning across the output streams showed 0.2% in the mill rejects, 8.7% in the bottom ash, 89.9% in the flyash and 1.2% in the stack flue gas stream. Major element partitioning found 0.2% in the mill rejects, 13.1% in the bottom ash, 86.3% in the flyash and 0.6% in the stack flue gas.
- For the trace elements mercury and selenium were found primarily in the stack exhaust.

**TABLE 5.3-1  
SUMMARY OF PARAMETERS TESTED IN EACH PROCESS STREAM NYSEG MILLIKEN UNIT 2**

Target Compounds	Boiler/SP Process Streams			Wastewater Process Streams		
	Coal Mill (PSS)	Bottom Ash	ESP Fly-ash	Coal Pile Run-off	Mill Run-off	Mill Sludge
1. Trace Elements	X		X	X		
2. Trace Elements						
2a. Total/Hexavalent Chromium						
2b. Mercury						
3. Major Elements						
4. Solid Particulate/Ash Content	X		X	X		
5. Acid-forming Anion Precursors	X		X			
6. Semi-volatile Organic Compounds						
6a. Polycyclic Aromatic Hydrocarbons						
6b. PCDD/PCDF(1)						
7. Volatile Organic Compounds						
7a.						
7b.						
8. Ammonia						
9. CEMS Data						
9a. NO <sub>2</sub> , SO <sub>2</sub> , CO <sub>2</sub> (Plant CEMS)						
9b. Diluent Gases - O <sub>2</sub> , CO <sub>2</sub>						
9c. Carbon Monoxide (CO)						
10. Ultimate Proximate Analysis			X			
11. Higher Heating Value			X			
12. Moisture			X			

**Notes:**

- (1) Polychlorinated dibenzo-p-dioxins/polychlorinated dibenzofurans
- (2) CO<sub>2</sub> measured at the stack only.
- (3) Ultimate/proximate and moisture analysis of solid-phase portion of ESP inlet flue gas samples.

**TABLE 5.3-2  
TARGET COMPOUND LIST  
NYSEG MILLIKEN UNIT 2**

TRACE ELEMENTS		
Antimony	Arsenic	Barium
Beryllium	Cadmium	Chromium (by two methods) <sup>2</sup>
Cobalt	Copper	Lead
Manganese	Mercury (by two methods) <sup>1</sup>	Molybdenum
Nickel	Phosphorus	Selenium
Vanadium		
MAJOR ELEMENTS		
Aluminum	Calcium	Iron
Magnesium	Potassium	Silicon
Sodium	Sulfur <sup>4</sup>	Titanium
VOLATILE ORGANIC COMPOUNDS		
Chloride	Fluoride	Sulfate
SEMI-VOLATILE ORGANIC COMPOUNDS		
Acenaphthene	Acenaphthylene	Anthracene
Benz(a)anthracene	Benzo(a)pyrene	Benzo(b)fluoroanthene
Benzo(g,h,i)perylene	Benzo(k)fluoranthene	Chrysene
Dibenzo (a,h)anthracene	Fluoranthene	Fluorene
Indeno(1,2,3-cd)pyrene	Naphthalene	Phenanthrene
Pyrene	2-Methylnaphthalene	3-Methylcholanthrene
	7,12-Dimethylbenz(a)anthracene	
Total for tetra-through octa-chlorinated homologues All 2,3,7,8 substituted isomers		
VOLATILE ORGANIC COMPOUNDS		
Benzene	Toluene	Formaldehyde
NITROGEN COMPOUNDS		
Ammonia		

**Notes:**

- (1) Total Hg was analyzed from the EPA Method 29 multi-metals sample train and elemental (Hg(0)), ionic (Hg(II)), and methyl Hg in addition to total were determined from the Frontier Geosciences train.
- (2) Total chromium was determined from the EPA Method 29 train and both hexavalent (Cr<sup>6+</sup>) and total Cr were obtained from the EPA recirculation train.
- (3) The test program scope was expanded to include a material balance for major ash elements to assess data quality.
- (4) Includes only ash-bound sulfur compounds that remain inert and do not vaporize during combustion.
- (5) Elemental precursors of anions measured in some process streams.

## **5.4 MILLIKEN AIR TOXICS & EMISSIONS CHARACTERIZATION**

The Milliken Air Toxics & Emissions Characterization program conducted baseline air toxic emissions characterization following the installation of the CCTD. Removal efficiencies were determined for key air toxic compounds (Hg, Ni, As, Be, Cd, Cr<sup>+6</sup>, BaP, dioxins and furans). A system mass balance was developed for the metals. The findings of this program are documented in the report entitled "Program Results from a Comprehensive Assessment of Chemical Emissions from New York State Electric & Gas Corporation's Milliken Station Unit 2" authored by Carnot, dated July 1997. What follows is a summary of this report. The full report can be obtained from DOE.

### **5.4.1 INTRODUCTION**

As part of the Department of Energy's (DOE) Clean Coal Technology Demonstration (CCTD) Program, New York State Electric & Gas (NYSEG) Corporation has installed and is operating a high-efficiency flue gas desulfurization (FGD) system for SO<sub>2</sub> emissions control, low-NO<sub>x</sub> burners for NO<sub>x</sub> emissions control, and electrostatic precipitator (ESP) and coal mill upgrades for particulate emissions control. This installation was completed to demonstrate innovative emissions control technology. This demonstration program was conducted at NYSEG's Milliken Station, Units 1 & 2, in the Town of Lansing, New York. The primary objective of this CCTD project was to show that a retrofit of energy-efficient SO<sub>2</sub>, NO<sub>x</sub> and particulate control systems can be made without a significant impact on overall plant efficiency.

The FGD uses a forced oxidation, formic acid-enhanced wet limestone system to reduce SO<sub>2</sub> emission by 90-98%. Commercial-grade gypsum and calcium chloride salt are marketable by-products of the FGD's zero wastewater discharge process. Up to 40% NO<sub>x</sub> reduction is achieved using the low-NO<sub>x</sub> burners, and the ESP and coal mill upgrades reduced ESP outlet particulate levels by a factor of ten.

To satisfy DOE's CCTD program requirements, NYSEG, through a competitive bidding process, selected Carnot to conduct a comprehensive measurement program to characterize the emissions of selected trace substances from Milliken Station's Unit 2, both pre- and post-retrofit of SO<sub>2</sub>, NO<sub>x</sub> and particulate control systems. Prior to the pollution control system upgrades, Carnot performed a "baseline" comprehensive trace substance measurement program on Unit 2 in 1994. This report presents the results of the post-retrofit test program performed in August 1996 and compares them to baseline data.

To continue researching the viability and applicability of certain wet chemical techniques for collecting and subsequently detecting and quantifying species of mercury in coal-fired utility boiler flue gas streams, Carnot, under an extended contract with NYSEG with the cooperation and support of DOE, and the Energy & Environmental Research Center (EERC) at the University of North Dakota, under a separate contract with EPRI, performed a utility-scale field evaluation of two promising techniques, the Ontario-Hydro and TRIS Buffer, for mercury speciation. Since EPA Method 29 and Frontier

Geosciences' solid sorbent scrubber technique were already part of the post-retrofit test program scope, by expanding the program to include the Ontario-Hydro and TRIS Buffer methods, EPRI, DOE and NYSEG were afforded the opportunity to compare all four mercury measurement techniques under full-scale conditions. Although EPA Method 29 and Frontier Geoscience have been used extensively to measure mercury on full-scale test programs, Ontario-Hydro and TRIS Buffer sampling methods have not been included. Prior evaluations under bench- and pilot-scale conditions comparing these four methods have shown them to be in general agreement on total mercury.

EERC also operated a mercury instrumental analyzer at the FGD outlet/stack location. It should be noted that this test program did not attempt to evaluate all mercury speciation methods currently in development. This report also presents the results of these mercury speciation tests.

## **5.4.2 SUMMARY OF RESULTS**

A summary of key post-retrofit test program results are provided in the following tables:

Table 5.4-1:	Summary of Unit Operation and Criteria Pollutant Emissions
Table 5.4-2:	ESP and FGD Removal Efficiencies for Inorganic Species
Table 5.4-3:	Summary of Detected Organic Species
Table 5.4-4:	Summary of Mercury Speciation Test Results
Table 5.4-5:	Comparison of Inorganic Element Flue Gas Emission Levels, Pre- and Post-Retrofit Test Programs

The following major conclusions were drawn from the results of this test program:

### **FLUE GAS TEST RESULTS**

- The ESP was effective at removing trace elements found primarily in the solid phase from the flue gas stream with an average removal efficiency of 99.7%. Major ash elements were effectively removed by the ESP at an average efficiency of 99.9%. The FGD removed trace elements at an average removal efficiency of 36.0%, and major elements at an average efficiency of 62.6%. The ESP removal efficiency for mercury was 16.7% and the FGD removal efficiency was 59.8%. Thus, overall removals by the ESP and scrubber combined were 99.81% for trace elements found primarily in the solid phase, 99.96% for major ash elements and 66.5% for mercury.
- With the exception of selenium, ESP inlet trace and major element results are in good agreement with coal input levels. From comparisons with coal input and flyash levels, selenium results for the ESP inlet and ESP outlet are severely biased low. Severe negative matrix interferences from the high levels of sulfur found in the ESP inlet and ESP outlet samples hindered their analyses for selenium. It is now believed that sulfur interferences are the main source for the low biases associated with the selenium analytical results for Milliken Unit 2. Given the low levels of sulfur contained in the stack EPA Method 29 samples and the lack of matrix interferences encountered during analysis, the stack selenium results are considered valid.



- Reported hexavalent chromium results show that the ESP and FGD combined to remove hexavalent chromium from the flue gas stream at an efficiency of 26%. This efficiency is likely understated since the hexavalent chromium level at the stack was 4.2 times higher than the total chromium value measured by the EPA Method 29 sample train.
- The ESP removal efficiency for filterable particulate was 99.88%. ESP and coal mill upgrades for the post-retrofit test program reduced ESP outlet particulate concentrations by almost a factor of ten when compared to pre-retrofit levels. Retrofit stack particulate emissions averaged 0.007 gr/dscf or 0.014 lb/10<sup>6</sup> Btu.
- Chloride, fluoride, and sulfur were found predominantly in the gaseous phase. The FGD was effective at removing chloride, fluoride and sulfur from the flue gas with average removal efficiencies of 99.4%, 98.7% and 93.1%, respectively. Mass balance results confirm particulate and anion flue gas concentration levels.
- For PAH emissions, only naphthalene, 2-methylnaphthalene, phenanthrene, and fluoranthene were measured at the stack at levels two times higher than the analytical detection limit or notably above field blank values. No dioxin or furan isomers were detected at levels greater than twice the field blank.
- Benzene concentrations measured at the ESP outlet averaged 2.3 ppb compared to 1.1 ppb at the stack. This difference across the FGD is not considered significant. Average toluene concentrations measured at the ESP outlet of 23 ppb were significantly higher than that of 7.2 ppb measured at the stack. It is not clear whether this difference is due to actual FGD removal or if it is just an artifact of measurement uncertainty.
- Stack formaldehyde emissions averaged 9.2 ppb which was 10 times higher than ESP outlet concentrations measured at 0.9 ppb. A possible source for the additional formaldehyde is the formic acid, which can have formaldehyde as an impurity, used by the FGD process. On the other hand, stack formaldehyde sample and field blank levels were similar.
- ESP outlet SO<sub>3</sub> concentrations were 5.8 ppm compared to 4.9 ppm at the stack.
- Particle size distribution at the ESP outlet averaged 76% less than 10 microns, 56% less than 2.5 microns, and 36% less than 1 micron.

#### **BOILER/ESP AND FGD MASS BALANCE RESULTS**

- In general, material balances were excellent for the post-retrofit test program. With the exception of selenium, all trace element and anion precursor (i.e. chlorine, fluorine, and sulfur) balances fell within the acceptable range of 70-130%, with most

balances between 80-115%. All major element balances fell within the acceptable range of 80-120% range, with most between 90-110%.

- Excellent FGD balances can be seen for trace and major elements (including anion precursors) existing in the ESP outlet/FGD inlet flue gas at levels above 1 lb/10<sup>12</sup>Btu. For trace elements above this level in which an FGD balance could be reported, namely arsenic and mercury, balances ranged from 92-107%; for the major elements (excluding phosphorus and sodium), balances were consistently between 93-112%; and for the anion precursors, FGD closures fell within 97-102%.

### **WASTEWATER TREATMENT PLANT TEST RESULTS**

- WWTP removal efficiencies of around 75% or greater were seen for most target inorganic elements detected in the WWTP inlet stream. The treatment plant exhibited low removals for barium (12%), vanadium (46%), phosphorus (52%) and fluoride (46%). Negative or very low removals were seen for many of the water soluble elements (i.e. Ca, Mg, K, Na, Cl, S, N) suggesting that another input stream to the WWTP was a significant source of these elements, such as chemical treatment additives (e.g. lime and ferric chloride).

### **MERCURY SPECIATION TEST RESULTS**

- For the FGD outlet/stack location, excellent agreement between the Frontier Geoscience, Ontario-Hydro and TRIS Buffer measurements can be seen for Hg(0) and Hg(II). Hg(0) results ranged from 2.45-2.94 µg/Nm<sup>3</sup> (excluding Method 2) and Hg(II) results ranged from 0.15-0.35 µg/Nm<sup>3</sup> (excluding Method 29). Good to excellent agreement exists between Frontier, Ontario-Hydro, TRIS and EPA Method 29 for total mercury with results ranging from 2.66-3.29 µg/Nm<sup>3</sup>.
- For the ESP outlet/FGD inlet, excellent agreement between Frontier, Ontario-Hydro, and TRIS can be seen for Hg(0) with levels ranging from 2.28-2.70 µg/Nm<sup>3</sup>.
- For the ESP outlet/FGD inlet, Ontario-Hydro and TRIS Buffer values are in good agreement for Hg(II); and Ontario-Hydro, TRIS and EPA Method 29 are in excellent agreement for total mercury.
- In comparison with the Ontario-Hydro and TRIS Buffer results, the EPA Method 29 mercury speciation values obtained from this test program exhibit a high bias for Hg(II), and a low bias for Hg(0).
- There is excellent agreement between the average FGD outlet/stack Hg(0) result as measured by the Semtech mercury analyzer with the other valid measurements at that location.
- FGD removal efficiencies were between 95-97% for Hg(II) (excluding EPA Method 29) and 59-65% for total mercury.

- Boiler/ESP mass balance results using Frontier Geoscience, Ontario-Hydro, TRIS Buffer, and EPA Method 29 total mercury values yielded 103%, 83%, 78%, and 85% agreement, respectively, between process streams.
- Total mercury FGD mass balance results for Frontier Geoscience, Ontario-Hydro, TRIS Buffer, and EPA Method 29 were 79%, 90%, 99%, and 93%, respectively.

## **COMPARISON BETWEEN PRE- AND POST-RETROFIT TEST PROGRAMS**

- The most notable difference between the baseline and post-retrofit test programs is that baseline testing was conducted while firing a 100% pre-cleaned coal, while a 50/50 mix between raw and pre-cleaned coal was burned during the post-retrofit program.
- The second most notable difference is that the upgrades to the ESP and coal mills improved particulate removal efficiency from 98.95% to 99.88%, reducing ESP outlet particulate concentrations by a factor of ten.
- A 45.4% NO<sub>x</sub> reduction can be seen between the two test programs with baseline stack emissions falling from 452 ppm @ 3% O<sub>2</sub> to 247 ppm @ 3% O<sub>2</sub>.
- Notable differences in fuel composition and unit operation between the test programs include an increase in fuel sulfur from 1.9% (baseline) to 2.3% (post-retrofit), an increase in fuel ash from 7.1% to 9.6%, and a higher boiler O<sub>2</sub> during baseline testing of 3.8% versus 3.1% for the post-retrofit program.
- For the ESP inlet, notable differences between concentration levels of target elements are consistent with those seen for the coal and flyash. It should be noted that ESP inlet and ESP outlet flue gas selenium levels for both test programs severely biased low as a result of severe matrix interferences from sulfur. It should also be noted that pre-retrofit ESP outlet mercury level is biased high.
- Baseline ESP outlet particulate concentrations were reduced by 88% following the ESP and coal mill upgrades. This reduction in ESP outlet particulate levels directly corresponds to substantially reduced concentrations of trace and major elements exiting the ESP. Baseline ESP outlet trace element concentrations were reduced by 89% (excluding vapor phase elements of mercury, selenium, and anion precursors, in addition to molybdenum), and major element concentrations were reduced by 81%, for an overall reduction in trace and major elements of 86%.
- The large discrepancy between baseline and post-retrofit hexavalent chromium concentrations measured at the ESP inlet suggests that either one or both of the test programs' reported results are in error. Comparisons between mercury species flue gas results were not presented on table 5.4-5 due to concerns regarding baseline mercury speciation data validity.

- The apparent increase in ESP outlet molybdenum concentrations for the post retrofit program is not representative of any actual changes in flue gas concentration; rather it is an artifact of blank corrections since molybdenum was found at blank levels for both programs.
- The FGD in combination with the upgraded ESP reduced trace and major element emissions slightly further with an overall reduction in baseline levels of 87% for the same group of elements (with the addition of magnesium). The FGD/ESP substantially reduced baseline mercury levels by 71% and baseline chloride, fluoride, and sulfur levels by an average of 96%.
- Post-retrofit FGD outlet/stack emissions of magnesium were 53% higher than baseline emissions. This is most likely due to magnesium found within fugitive limestone particles exiting the FGD.
- For the volatile organic elements, the post-retrofit FGD and ESP upgrades combined to reduce baseline benzene emissions by 52%. However, post-retrofit FGD outlet/stack emissions of toluene and formaldehyde were 2-3 times higher than baseline emissions.

**TABLE 5.4-1  
SUMMARY OF UNIT OPERATION AND CRITERIA POLLUTANT EMISSIONS  
NYSEG MILLIKEN UNIT 2 POST-RETROFIT TEST PROGRAM  
AUGUST 1996**

Unit Type	CE, tangentially-fired	
Fuel Type	Eastern Bituminous Coal	
Fuel Sulfur Level	2.2-2.4%	
Air Pollution Control Devices	Low-NO <sub>x</sub> Burners, ESP & FGD	
Test Period	Inorganic Elements Measurement Period	Organic Elements Measurement Period
Test Dates	August 7-9, 1996	August 12-13, 1996
Unit Load, MW <sub>net</sub>	149	148
Coal Flow Rate, klb/hr	118.7	120.7
Boiler O <sub>2</sub> %	3.3%	2.8%
FGD Inlet Opacity, %	5.8	6.0
SO <sub>2</sub> , dry ppm @ 3% O <sub>2</sub>		
FGD Inlet	1805	1677
FGD Outlet	142	93
FGD Removal Efficiency	92.1%	94.4%
SO <sub>3</sub> , dry ppm @ 3% O <sub>2</sub>		
FGD Inlet	6.8	NP
FGD Outlet	5.7	NP
FGD Removal Efficiency	15.3%	--
NO <sub>x</sub> , dry ppm @ 3% O <sub>2</sub> (FGD Outlet)	227	267
NO <sub>x</sub> , lb/10 <sup>6</sup> Btu (FGD Outlet)	0.304	0.357
Particulate Matter, lb/10 <sup>6</sup> Btu		
ESP Inlet	6.35	NP
ESP Outlet/FGD Inlet	0.007	NP
ESP Removal Efficiency	99.88%	--
FGD Outlet	0.014	NP

NP: Measurement not performed during this test period

Note: Unit operating data and criteria pollutant emissions results are from Unit 2 operation logs except for SO<sub>3</sub> and Particulate Matter which are from Camot's measurements.

**TABLE 5.4-2**  
**ESP AND FGD REMOVAL EFFICIENCIES FOR INORGANIC SPECIES**  
**NYSEG MILLIKEN UNIT 2 POST-RETROFIT TEST PROGRAM**  
**AUGUST 1996**

Species	<u>Inorganic Flue Gas Emissions, lb/10<sup>12</sup>Btu</u>			ESP Removal Efficiency	FGD Removal Efficiency
	ESP INLET	ESP OUTLET	STACK		
<b>Trace Elements</b>					
Antimony	23	0.19	ND< 0.08	99.17%	> 57.3%
Arsenic	489	1.7	0.91	99.65%	47.3%
Barium	4,869	2.1	1.2	99.96%	41.3%
Beryllium	52	0.03	0.02	99.94%	31.4%
Cadmium	3.5	ND< 0.04	0.05	> 98.77%	--
Chromium	689	0.20	0.15	99.97%	25.0%
Hexavalent Chromium	0.85	NP	0.63	--	25.9%
Cobalt	183	0.12	0.12	99.94%	--
Copper	475	0.90	0.69	99.81%	24.1%
Lead-	309	0.56	0.63	99.82%	--
Manganese	1,373	0.61	1.9	99.96%	--
Mercury	6.89	5.74	2.31	16.75%	59.7%
Molybdenum	97	0.39	0.35	99.60%	9.4%
Nickel	528	0.15	0.33	99.97%	--
Selenium <sup>(1)</sup>	26	35	2.1	NV	NV
Vanadium	1,129	1.1	0.69	99.90%	39.1%
<b>Anion Precursors</b>					
Chlorine					
Solid Fraction	2,362	ND< 3.1	ND< 3.3	> 99.87%	--
Gaseous Fraction	62,828	65,157	396	--	99.4%
Total	65,190	65,159	398	0.05%	99.4%
Fluorine					
Solid Fraction	969	69.4	5.3	92.84%	92.3%
Gaseous Fraction	5,592	6,423	80	--	98.8%
Total	6,561	6,492	85	1.05%	98.7%
Sulfur					
Solid Fraction	28,372	1,126	2,082	96.03%	--
Gaseous Fraction	1.84E+06	1.72E+06	1.17E+05	6.52%	93.2%
Total	1.87E+06	1.73E+06	1.19E+05	7.88%	93.1%
<b>Particulate, lb/10<sup>6</sup>Btu</b>	6.35	0.007	0.014	99.88%	--
<b>Major Elements</b>					
	<u>lb/10<sup>6</sup>Btu</u>	<u>lb/10<sup>12</sup>Btu</u>	<u>lb/10<sup>12</sup>Btu</u>		
Aluminum	0.675	155	61	99.98%	60.6%
Calcium	0.228	196	259	99.91%	--
Iron	0.821	85	27	99.99%	68.6%
Magnesium	0.037	15	104	99.96%	--
Phosphorus	0.017	66	15	99.62%	76.5%
Potassium	0.092	28	ND<38	99.97%	--
Sodium	0.038	108	141	99.72%	--
Titanium	0.035	11	6.3	99.97%	44.7%

ND<: parameter not detected

NP: measurement not performed

NV: not valid

Note: (1) From comparisons with coal feed and flyash levels, selenium results for the ESP inlet and outlet are severely biased low; subsequently ESP and FGD removal efficiencies are not valid for selenium.

**TABLE 5.4-3  
SUMMARY OF DETECTED ORGANIC SPECIES  
NYSEG MILLIKEN UNIT 2 POST-RETROFIT TEST PROGRAM  
AUGUST 1996**

Parameter	Trace Organic Measurements, lb/10 <sup>12</sup> Btu		
	ESP Inlet	ESP Outlet	Stack
<b>Polycyclic Aromatic Hydrocarbons:</b>			
Naphthalene	7.2	9.4	10
2-Methylnaphthalene	0.028	0.027	0.23
Acenaphthylene	ND< 0.002	0.003	ND< 0.006
Acenaphthene	0.015	ND< 0.057	ND< 0.009
Phenanthrene	0.003	ND< 0.022	0.10
Anthracene	0.020	0.014	ND< 0.003
<b>PCDD/PCDF Isomers</b>			
2378-TCDD	ND< 1.5E-06	1.8E-06	1.7E-06
12378 PeCDD	1.4E-06	1.2E-06	ND< 1.3E-06
123478 HxCDD	3.7E-06	3.4E-06	3.2E-06
1234678 HpCDD	2.1E-06	8.6E-07	ND< 2.1E-06
OCDD	9.0E-06	3.4E-06	6.5E-06
2378 TCDF	ND< 1.9E-06	ND< 7.5E-07	2.2E-06
12378 PeCDF	8.5E-07	ND< 7.3E-07	ND< 5.8E-07
23478 PeCDF	ND< 1.0E-06	ND< 8.6E-07	1.0E-06
123789 HxCDF	2.9E-06	ND< 4.7E-06	3.1E-06
OCDF	1.9E-06	ND< 1.1E-06	2.4E-06
<b>Volatile Organic Compounds:</b>			
Benzene	NP	6.7	3.4
Toluene	NP	56	19
Formaldehyde	NP	0.83	8.8

ND<: species not detected

NP: measurement not performed

Note: (1) No PCDD or PCDF isomers were detected at levels greater than twice the field blank.

**TABLE 5.4-4**  
**SUMMARY OF MERCURY SPECIATION TEST RESULTS**  
**NYSEG MILLIKEN UNIT 2 POST-RETROFIT TEST PROGRAM**  
**AUGUST 1996**

Mercury Species Test Method	Emission Results, $\mu\text{g}/\text{Nm}^3$			ESP Removal Efficiency <sup>(1)</sup>	FGD Removal Efficiency <sup>(1)</sup>
	ESP INLET	ESP OUTLET/ FGD INLET	FGD OUTLET/ STACK		
<u>Hg(0) - Elemental</u>					
EPA Method 29	0.80	1.49	2.40	--	--
Frontier Geoscience	2.12	2.66	2.94	--	--
Ontario-Hydro	--	2.28	2.45	--	--
TRIS Buffer	--	2.70	2.71	--	--
Semtech Hg 2000 Analyzer <sup>(2)</sup>	--	NV	2.61	--	--
<u>Hg(II) - Oxidized</u>					
EPA Method 29	7.43	6.23	0.62	18%	90%
Frontier Geoscience	6.93	6.82	0.35	5%	95%
Ontario-Hydro	--	5.24	0.21	--	96%
TRIS Buffer	--	4.46	0.15	--	97%
<u>Hg (total) - Hg Solids</u>					
EPA Method 29	0.86	ND<0.009	0.006	99.5%	--
Frontier Geoscience <sup>(3)</sup>	0.06	0.07	0.003	--	--
Ontario-Hydro	--	0.0003	0.0009	--	--
TRIS Buffer	--	0.002	0.004	--	--
<u>TOTAL Hg<sup>(4)</sup></u>					
EPA Method 29	9.09	7.72	3.02	17%	60%
Frontier Geoscience	9.11	9.56	3.29	--	65%
Ontario-Hydro	--	7.52	2.66	--	64%
TRIS Buffer	--	7.16	2.87	--	59%

NV -- results not valid. Semtech analyzer measurements performed at this location were deemed invalid due to the use of an improper sample conditioning system and detrimental ambient conditions (i.e. high temperature and dust level).

Notes:

- (1) Removal efficiencies calculated using emission units of lb/10<sup>12</sup>Btu to account for any differences in flue gas dilution between locations.
- (2) The Semtech Hg 2000 analyzer only measures elemental mercury.
- (3) The Frontier Geoscience method is not designed to representatively quantify the mercury solids fraction. These values represent mercury vapor that adsorbed on the flyash collected on the quartz wool plug during sampling.
- (4) Total Hg is the sum of Hg(0), Hg(II), and Hg solids.



**TABLE 5.4-5  
COMPARISON OF INORGANIC ELEMENT FLUE GAS EMISSION LEVELS  
PRE- AND POST-RETROFIT TEST PROGRAMS  
NYSEG MILLIKEN UNIT 2**

Target Parameter	ESP INLET <sup>(1)</sup>			ESP OUTLET <sup>(2)</sup>			FGD OUTLET/STACK <sup>(3)</sup>	
	Pre-Retrofit Concentrations	Post-Retrofit Concentrations	Relative Percent Diff.	Pre-Retrofit Concentrations	Post-Retrofit Concentrations	Post-Percent Reduction <sup>(4)</sup>	Post-Retrofit Concen.	Percent Reduction <sup>(5)</sup>
<b>Particulate Matter, lb/10<sup>12</sup>Btu</b>								
	5.75	6.35	10%	0.060	0.007	88%	0.014	77%
<b>Trace Elements lb/10<sup>6</sup>Btu</b>								
Antimony	30	23	26%	ND<0.51	0.19	--	ND<0.08	--
Arsenic	475	489	3%	10	1.73	83%	0.91	91%
Barium	3,051	4,869	46%	8.4	2.1	75%	1.2	85%
Beryllium	72.3	52	32%	0.76	0.03	96%	0.02	97%
Cadmium	7.8	3.5	76%	0.34	ND<0.04	87%	0.05	84%
Chromium	894	689	26%	6.2	0.20	97%	0.15	98%
Hexavalent Chromium	8.6	0.85	164%	ND<0.07	NP	--	0.63	--
Cobalt	198	183	8%	2.2	0.12	95%	0.12	94%
Copper	357	475	28%	4.2	0.90	79%	0.69	84%
Lead	276	309	11%	5.4	0.56	90%	0.63	88%
Manganese	928	1,373	39%	8.1	0.61	92%	1.9	76%
Mercury	6.4	6.89	7%	8.1	5.74	29%	2.31	71%
Molybdenum	78	97	22%	0.17	0.39	-129%	0.35	-108%
Nickel	592	528	11%	5.3	0.15	97%	0.33	94%
Selenium	58	26	76%	30	35	-17%	21	30%
Vanadium	1,447	1,129	25%	12	1.1	91%	0.69	94%
<b>Anion Precursors, lb/10<sup>12</sup>Btu</b>								
Chlorine	64,476	65,190	1%	69,222	65,159	6%	398	99%
Fluorine	4,536	6,561	37%	4,259	6,492	-52%	85	98%
Sulfur	1.31E+06	1.87E+06	35%	1.36E+06	1.73E+06	-27%	1.19E+05	91%
<b>Major Elements lb/10<sup>6</sup>Btu</b>								
Aluminum	0.624	0.675	8%	4,459	155	97%	61	99%
Calcium	0.097	0.228	80%	467	196	58%	259	45%
Iron	0.617	0.821	28%	2,634	85	97%	27	99%
Magnesium	0.024	0.037	45%	68	15	78%	104	-55%
Phosphorus	0.011	0.017	46%	155	66	58%	15	90%
Potassium	0.069	0.092	29%	452	28	94%	ND<38	91%
Sodium	0.021	0.038	60%	364	108	70%	141	61%
Titanium	0.034	0.035	3%	208	11	94%	6.3	97%

Notes:

- (1) ESP INLET = flue gas concentrations at the boiler exit or inlet to the ESP.
- (2) ESP OUTLET = flue gas concentrations at the outlet of the ESP; for the pre-retrofit test program the ESP Outlet and Stack are syn sample locations.
- (3) FGD OUTLET/STACK = FGD outlet flue gas emissions; only applicable to the post-retrofit test program.
- (4) Percent Reduction of flue gas emissions due to the ESP upgrades = (Pre-Retrofit ESP Outlet Level - Post-Retrofit ESP Outlet Level) / Pre-Retrofit ESP Outlet Level
- (5) Percent Reduction of flue gas emissions due to the combined effect of the ESP upgrades and FGD = (Pre-Retrofit ESP Outlet Level - Post-Retrofit Stack Level) / Pre-Retrofit ESP Outlet Level

## **5.5 MILLIKEN WATER TOXICS TREATMENT & CHARACTERIZATION**

The scope of the Milliken Water Toxics Treatment & Characterization Program included evaluating heavy metals removal in the FGD bleed stream and determining parameters for controlling mercury removal and total treatment efficiency. The scope also included determining the ultimate disposal and treatment of heavy metal sludge and costs for entire treatment.

At the time of publication of this Project Performance and Economics Report the results of the Milliken Water Toxics Treatment & Characterization Program had not been published. When the results of this program become available they will be the subject of a Topical Report.

## **5.6 MILLIKEN POST-RETROFIT TRUE EVALUATION**

The Milliken Post-Retrofit TRUE Evaluation used the EPRI TRUE (Total Risk and Uncertainty Evaluation) model to assess the potential for the CCTD to mitigate transferal of toxic materials from the plant site to the ambient environment. Possible transferal routes included in the study were stack emissions and contaminated water discharge streams. The risk management approach was used to demonstrate the capability of the Milliken project to mitigate health and ecological risks in the vicinity of the station. The TRUE model allows a comprehensive evaluation of the movement of hazardous pollutants into and through many environmental pathways and the manners in which humans and ecosystems may be exposed to these pollutants. The findings of this program are documented in the following reports

- “Ecological Risk Assessment for the NYSEG Milliken Station” authored by Atmospheric and Environmental Research, Inc. (AER) , dated February 1998. This report covers risks due to stack emissions.
- “Multimedia Human Health and Ecological Risk Assessment for the Potential Wastewater Discharge of the NYSEG Milliken Station” authored by Atmospheric and Environmental Research, Inc. (AER) , dated February 1998. This report covers risks due to wastewater discharge.

What follows are summaries of these reports. The full reports can be obtained from DOE.

### **5.6.1 ECOLOGICAL RISK ASSESSMENT (ERA)**

The installation of the flue gas desulfurization (FGD) system at Milliken Station to control sulfur dioxide (SO<sub>2</sub>) emissions provided a unique opportunity to study the benefits that the FGD system affords to ecological receptors in the general area around the station. This was accomplished by performing an ecological risk assessment (ERA). An ERA is a process which evaluates the likelihood that adverse ecological effects are occurring or may occur as a result of exposure of ecological receptors to one or more environmental stressors. An environmental stressor is a physical, chemical, or biological factor which can induce an adverse ecological response. For the Milliken ERA, the stressor of potential concern was mercury released to the atmosphere as a result of fuel combustion at Milliken Station. The ERA characterized the potential risk posed by emissions from the Milliken Station before and after implementation of the (FGD) system. The ecological habitats and resources at or in the vicinity of the Milliken Station were characterized. These include wetlands and local water bodies, terrestrial uplands, threatened and endangered species, and important ecological features within a 50 km radius of the facility.

The AER report includes a discussion of the problem formulation and general methodology for completing the ERA; a description of the ecological habitat in a 50 km radius around the power plant and an assessment of potential ecological receptors,

including rare, threatened and endangered species which may exist in the study area; an analysis of risk in the study area, including exposure assessment and ecological effects; a description of the models used and their results; an assessment of mercury as a contaminant of concern with a discussion of the uncertainties associated with the assessment, and AER's conclusions resulting from the NYSEG Milliken Station ERA investigations.

The results of the Milliken Station ERA for the pre-retrofit conditions indicated no potential ecological concern due to pre-retrofit mercury emissions from the Milliken Station for any of the aquatic or terrestrial ecological receptors. The analysis indicated that the predominant source of risk to all of the receptors is through the surface water exposure pathway, either through direct ingestion or through consumption of aquatic organisms with bioaccumulated mercury. All of the modeled media concentrations were well below screening values and the results of the food web modeling produced no Hazard Quotients (HQ's) which exceeded 1.0. For the aquatic receptors, the highest risk was due to methylmercury in the sediment, but the HQ (0.0033) was two orders of magnitude below a level of concern. For the wildlife receptors, the greatest risk was indicated for the top trophic predators in the aquatic pathway (i.e., mink (HQ = 0.15); bald eagle (HQ = 0.26)), but again below the level of concern. These results indicate that the pre-retrofit conditions do not lead to mercury emissions that have adverse impacts on the local environment.

The post-retrofit risk characterization indicated that there were no exceedances of ecotoxicological benchmarks or  $HQ > 1.0$  for either total mercury or methylmercury for any of the ecological receptor communities or representative species due to current emissions from the Milliken Station facility. The highest HQ's observed were for bald eagle (HQ = 0.0015) and mink (HQ = 0.0043); both of which are below potential concern. Overall, these results indicate negligible ecological risk associated with the future mercury smokestack emissions. Potential future ecological risks are approximately one order of magnitude less than those estimated for the pre-retrofit scenario.

## **RISK ANALYSIS**

Risk analysis assesses the potential exposure of mercury to ecological receptors of concern and describes the potential adverse effects associated with exposure.

### **Exposure Assessment**

Two models were used to estimate media mercury concentration in the relevant environmental media (i.e. soils, water, sediment). The Total Risk of the Utility Emissions (TRUE) model, developed by AER, ENSR, and Geodesy for EPRI, was used to provide the mercury concentration in the surface soil layer, the atmospheric concentrations of mercury, and the atmospheric deposition fluxes of mercury to watersheds. The soil concentrations of mercury were used directly as an input for the ERA calculations. The atmospheric concentrations and deposition fluxes were used as an input to the Regional

Mercury Cycling Model (R-MCM). R-MCM is a steady-state mechanistic model developed by TetraTech for EPRI and the Wisconsin Department of Natural Resources (WDNR). R-MCM is used to consider the most important factors affecting fish mercury concentrations in lakes and the nature of variation in concentrations between lakes.

The exposure point concentrations of mercury were predicted from TRUE (soil concentrations) and R-MCM (water and sediment concentrations). These models provide mercury concentrations in several forms and locations. The concentrations predicted from R-MCM for total mercury and unfiltered or total methylmercury in the epilimnion compartment were used to model mercury exposure in surface water. Similar to the surface water, total mercury and methylmercury deposited in the sediments were predicted by R-MCM. It was assumed in the ERA that all of the sediment mercury is bioavailable. This is conservative as some portion is likely to be associated with the sediment matrix. Soil and plant exposure concentrations were estimated using results from the TRUE model. The form of mercury deposited in soils is typically Hg(II), but this was treated as total mercury. In addition, the fraction of soil mercury translocated to plants and biotransformed into methyl mercury is not known. Accordingly, mercury uptake by plants was total mercury.

Food web models were used to evaluate the potential exposure of ecological receptors to mercury in various media. Food web models are typically used to evaluate risk to bioaccumulative chemicals such as mercury.

Exposure assumptions (e.g., body weights, food and water ingestion rates, relative consumption of food items, foraging range, exposure duration, etc.) for the selected wildlife receptor species are, in general, obtained from the U.S. EPA Wildlife Exposure Factors Handbook (EPA, 1993).

Wildlife species were assumed to be exposed to mercury in surface water, sediment, and surface soil by incidental ingestion of these media. In addition, wildlife were assumed to be exposed through the food chain tissue ingestion exposure pathway and through ingestion of vegetation which had bioaccumulated mercury from soil. To estimate this exposure, a Total Daily Dose was estimated for each species. The Total Daily Dose calculation considered the following factors: estimated concentration of mercury in food items that the species would consume, estimated amounts of surface water, sediment, and surface soil that it would ingest, the relative amount of different food items in its diet, body weight, exposure duration, and food ingestion rates.

Prey items for wildlife species evaluated in the food web exposure models included invertebrates, plants, small mammals, and small birds. Tissue concentrations of mercury in invertebrate prey items were estimated using Bioaccumulation Factors (BAF's). BAF's in invertebrate prey items were defined as the ratio of mercury concentration in tissue to the mercury concentration in surface soil. Tissue concentrations of avian and mammal receptors were estimated using biomagnification factors (BMF's) as per the Great Lakes Water Quality Initiative Criteria Documents for the Protection of Wildlife (USEPA, 1995).

Biomagnification factors take into account several trophic levels, and were conservatively estimated in this project. In addition, the R-MCM provided prey fish and predator fish BAF's which were used for estimation of prey and predator fish mercury concentrations.

Resulting potential daily doses of mercury (mg/kg-day) for the representative vertebrate species were compared to respective toxicity reference values (TRV's). TRV's are protective benchmark values for vertebrate wildlife species and were derived in accordance with U.S. EPA guidance (Sample, et.al., 1996). Experimentally derived toxicity values were adjusted for body weight and used as the toxicological benchmark for wildlife species.

### **Ecological Effects Evaluation**

Mercury was selected as the contaminant of interest (COI) in the Milliken Station ERA. Mercury is an element that occurs naturally in the environment in several forms. Total mercury and the methylmercury (MeHg) fraction were evaluated in the Milliken Station ERA. Methylmercury is of particular concern in aquatic systems due to its tendency to bioaccumulate in the aquatic system food chain. Organic mercury is also generally more toxic to vertebrate wildlife than inorganic mercury. Potential exposure to mercury was evaluated in surface soil, sediment, and surface water.

### **RISK CHARACTERIZATION**

Risk characterization provides a quantitative evaluation of the potential for adverse ecological impacts due to compounds of interest (COI) in an area of concern. The COI in the Milliken Station ERA is mercury and the area of concern is Cayuga Lake and a 10 km radius around the power plant. The results of the risk characterization were used to indicate what effect installation of the Milliken scrubbers had on the potential ecological risk posed to receptors within the study area. To evaluate the potential ecological risk posed by mercury emitted by Milliken, media concentrations were compared to ecological benchmark toxicity values.

### **Ecological Benchmark Toxicity Values and Calculation of Potential Risk**

The potential risks associated with aquatic organism exposures to mercury in surface water and sediment were evaluated by comparing the modeled mercury concentrations in surface water and sediment to available toxicity benchmark values. Benchmark toxicity values were available for surface water for both methyl mercury and total mercury. The surface water benchmark values are protective of aquatic life including, but not limited to, aquatic invertebrate and fish species.

Concentrations of mercury in sediment were compared to benchmark screening values defined by NYSDEC. The value was originally derived as an ER-L (Effects Range - Low) value as published by NOAA. Although the value was derived for use in marine

sediments, it was used since it is the most conservative value, and it is the value used by NYSDEC. The ER-L was used for screening for total mercury.

The potential risks associated with plant and invertebrate exposures to mercury in surface soil in the study area were estimated through the use of literature-derived toxicity benchmark values. For plants, the benchmark value was obtained from the Oak Ridge National Laboratories publication entitled "Toxicological Benchmarks for Screening Potential Contaminants of Concern for Effects on Terrestrial Plants". For invertebrates, benchmark values were obtained from the Oak Ridge National Laboratories publication entitled "Toxicological Benchmarks for Screening Potential Contaminants of Concern for Effects on Litter Invertebrates and Geterotrophic Process". The values obtained are for total mercury.

Toxicity Reference Values (TRV's) were determined from literature for methylmercury and total mercury for each mammalian and avian species. TRV's relate the dose of a chemical or compound from oral exposure with an adverse effect. The literature values were body-weight normalized using scaling factors recommended for use by the Oak Ridge National Laboratories.

The modeled mercury concentrations in all media resulting from the incremental atmospheric mercury contribution from Milliken Station were compared to benchmark toxicity values to estimate ecological risk. The ecological risks in the study area for aquatic organisms (fish and macroinvertebrates) were assessed using the hazard quotient (HQ) approach (U.S. EPA, 1988). An HQ was calculated by dividing the maximum exposure point concentration of mercury by the corresponding toxicity benchmark concentration:

$$\text{Hazard Quotient (unitless)} = \frac{\text{Exposure Point Concentration}}{\text{Toxicity Benchmark Concentration}}$$

For vertebrate receptors (mink, bald eagle, shrew, vole, and hawk), the HQ was calculated by comparing the estimated daily dose (mg/kg-day) of mercury to vertebrate toxicity reference values (TRVs). When the HQ was less than 1.0 (i.e., the exposure point concentration was less than the toxicity benchmark concentration or the estimated daily dose was less than the toxicity reference value), the mercury exposure was assumed to fall below the range considered to be associated with adverse effects for growth, reproduction, or survival of individual organisms, and no population level risks were assumed to be present. For HQ values greater than 1, further evaluation of potential risk is warranted.

This hazard ranking scheme evaluates the potential for adverse effects to occur in individual organisms. It does not evaluate potential population-wide effects. It is important to note that, in many circumstances, lethal or sub-lethal effects may occur to individual organisms with little population or community-level impact.

## Pre-Retrofit Ecological Risk

To evaluate the effectiveness of the scrubber installation, it is first necessary to establish the potential ecological risk due to the baseline pre-retrofit facility emissions. Potential risks to ecological receptors were evaluated in the pre-retrofit scenario for the following media:

- Cayuga Lake surface water
- Littoral (near-shore) sediment
- Surface soils

The exposure point concentrations used in surface water and sediment evaluation were obtained from the R-MCM simulation results. Concentrations were estimated in R-MCM for the lake as a whole; there was no distinguishing between areas of greater or lesser deposition. For surface soil evaluation, the exposure point concentrations used were the maximum mercury concentrations obtained in the TRUE simulations. The area defined as the southeast sector within 10 km of the facility had the highest estimated mercury concentrations. The use of these soil concentrations to represent ecological risk is, therefore, conservative.

Table 5.6-1 presents the results of comparison of modeled concentrations of mercury in the above media to benchmark values. These concentrations of mercury are the estimated increment of mercury deposited in the environment as a direct result of the operation of the Milliken Station facility before the installation of scrubbers.

### Aquatic and Wetland Receptors

Potential risks to aquatic and wetland receptors due to pre-retrofit emissions from the Milliken Station were evaluated for Cayuga Lake surface waters and sediment. These media represent true aquatic habitat. Mercury concentrations were modeled using R-MCM.

- Surface Water. Predicted surface water concentrations were compared to the NYSDEC ambient water quality criteria. For purposes of this assessment, both total mercury and unfiltered or total (i.e., dissolved) methylmercury predicted concentrations in Cayuga Lake were well below their respective NYSDEC Tier II benchmark screening values. Resulting HQs were well below 1.0 for both total methylmercury and total mercury (HQ's = 1.67E-03 and 4.31 E-05, respectively).
- Sediment. Benchmark values for methylmercury and total mercury were obtained from NYSDEC (1993) and were compared to modeled concentrations of mercury in sediment. Methylmercury concentrations in near-shore sediment were estimated to be below the sensitivity level of R-MCM (i.e. < 0.001 mg/kg<sub>dw</sub>). Consistent with U.S. EPA Risk Assessment methodology, a value of one-half the reporting limit was used. Estimated concentrations of methylmercury and total mercury in sediment were less



than their respective benchmark values. Resulting HQ's were less than 1.0 (HQ's = 3.33E-03 and 6.67E-03, respectively).

### Terrestrial Receptors

Potential ecological risk to terrestrial receptors was estimated based on the exposure point concentration derived from TRUE (soil, plant) and R-MCM (surface water, sediments). Only total mercury (deposited as mercury (II)) was assumed to be present in surface soil as a result of deposition. This is an appropriate assumption for terrestrial upland soil where bacterial methylation would be expected to be minimal. The maximum modeled concentration was used as the exposure point concentration (Seigneur et al., 1997). The area southeast and within 10 km of the facility had the highest surface soil mercury concentration. This value was compared to benchmark values for terrestrial invertebrates and terrestrial plants.

The estimated concentration of total mercury in surface soil was less than invertebrate and plant benchmark values. Resulting HQ's were less than 1.0 (HQ's = 3.30E-11 and 1.10E-11, respectively).

### Vertebrate Receptors

The potential for adverse effect for vertebrate receptors was calculated using screening level food web models. Species-specific HQ's were calculated by dividing the estimated mercury dose (normalized to body weight) by toxicity reference values determined from the literature. The potential daily doses of methylmercury and total mercury were less than the respective toxicity reference values for the meadow vole (the representative primarily herbivorous mammalian receptor), the short-tailed shrew (the representative primarily insectivorous mammalian receptor), the red-tailed hawk (the representative avian raptor receptor), the bald eagle (the representative species for evaluating potential risks posed to higher trophic level avian species from sediment, surface soil, and surface water exposure), and the mink (the representative higher trophic level mammalian receptor).

### Post-Retrofit Ecological Risk

Potential risks to ecological receptors were evaluated in the post-retrofit scenario for the following media:

- Cayuga Lake surface water
- Littoral (near-shore) sediment
- Surface soils

As before, the exposure point concentrations used in surface water and sediment evaluation were obtained from the results of modeling using R-MCM using atmospheric impacts predicted after installation of scrubbers. All other factors were kept identical to

the pre-retrofit simulations. Table 5.6-1 presents the results of comparison of modeled concentrations of mercury in the above media to benchmark values. These concentrations of mercury are the estimated increment of mercury deposited in the environment as a direct result of the atmospheric deposition of mercury due to the operation of Milliken Station after the installation of stack scrubbers.

#### Aquatic and Wetland Receptors

Potential risks to aquatic and wetland receptors due to post-retrofit emissions from the Milliken Station were evaluated for Cayuga Lake surface waters and sediment. These media represent true aquatic habitat. Mercury concentrations were modeled using R-MCM.

- Surface Water. Comparison of predicted surface water concentrations to the NYSDEC ambient water quality criteria was again used. Methylmercury concentrations in epilimnion surface water were estimated to be below the sensitivity level of the R-MCM. Consistent with U.S. EPA Risk Assessment methodology, a value of one-half the reporting limit was used. Both total mercury and unfiltered or total (i.e., dissolved) methylmercury predicted concentrations in Cayuga Lake were well below their respective NYSDEC Tier II benchmark screening values. Resulting HQ's were well below 1.0 for both total methylmercury and total mercury (HQ's = 1.67E-04 and 3.85E-06, respectively).
- Sediment. Benchmark values for methylmercury and total mercury were obtained from NYSDEC (1993) and were compared to modeled concentrations of mercury in sediment. Methylmercury and total mercury concentrations in near-shore sediment were estimated to be below the sensitivity level of R-MCM (i.e. < 0.001 mg/kg<sub>dw</sub>). Consistent with U.S. EPA Risk Assessment methodology, a value of one-half the reporting limit was used. Estimated concentrations of methylmercury and total mercury in sediment were less than their respective benchmark values. Resulting HQ's were less than 1.0 (HQ's = 3.33E-03 and 3.33E-03, respectively).

#### Terrestrial Receptors

Potential ecological risk to terrestrial receptors was estimated based on the exposure point concentration derived from TRUE (soil, plant) and R-MCM (surface water, sediments) and assuming installation of the scrubbers. All other assumptions were identical to those used for the pre-retrofit analysis. Values were compared to benchmark values for terrestrial invertebrates and terrestrial plants.

The estimated concentration of total mercury in surface soil was less than invertebrate and plant benchmark values. Resulting HQ's were less than 1.0 (HQ's = 3.53E-12 and 1.18E-12, respectively).

## Vertebrate Receptors

The potential for adverse effect for vertebrate receptors was calculated using screening level food web models. Species-specific HQ's were calculated by dividing the estimated mercury dose (normalized to body weight) by toxicity reference values determined from the literature. The potential daily doses of methylmercury and total mercury were less than the respective toxicity reference values for the meadow vole (the representative primarily herbivorous mammalian receptor), the short-tailed shrew (the representative primarily insectivorous mammalian receptor), the red-tailed hawk (the representative avian raptor receptor), the bald eagle (the representative species for evaluating potential risks posed to higher trophic level avian species from sediment, surface soil, and surface water exposure), and the mink (the representative higher trophic level mammalian receptor).

### **Summary of Risk Characterization**

The pre-retrofit risk characterization indicated that there were no exceedances of ecotoxicological benchmarks (table 5.6-1) or  $HQ > 1$  for either total mercury or methylmercury for any of the ecological receptor communities or representative species due to pre-retrofit emissions from the Milliken Station facility. The highest HQ's observed were for bald eagle ( $HQ = 0.03$ ) and mink ( $HQ = 0.07$ ); both of which are below potential concern. Overall, these results indicate negligible ecological risk associated with the pre-retrofit mercury smokestack emissions.

The post-retrofit risk characterization indicated that there were no exceedances of ecotoxicological benchmarks (table 5.6-1) or  $HQ > 1$  for either total mercury or methylmercury for any of the ecological receptor communities or representative species due to current emissions from the Milliken Station facility. The highest HQ's observed were for bald eagle ( $HQ = 0.0015$ ) and mink ( $HQ = 0.0043$ ); both of which are below potential concern. Overall, these results indicate negligible ecological risk associated with the future mercury smokestack emissions. Potential future ecological risks are approximately one order of magnitude less than those estimated for the pre-retrofit scenario.

## **RISK ASSESSMENT**

### **Potential Ecological Risks Associated With Milliken Station**

The results of the both the pre-retrofit and post-retrofit risk characterizations indicate that there is no potential ecological concern due to pre-retrofit or post-retrofit mercury emissions from Milliken Station. All of the modeled media concentrations are well below screening values and the results of the food web modeling produce no HQ's which exceed 1.0. The relative importance of each of the exposure pathways was analyzed. This analysis indicates that the predominant source of risk to all of the receptors is through the surface water exposure pathway, either through direct ingestion or through

consumption of aquatic organisms with bioaccumulated mercury. The results of the food web modeling for both pre-retrofit and post-retrofit conditions indicates no potential ecological concerns for any of the 5 terrestrial and aquatic receptors.

### **Uncertainties In Ecological Risk Assessment**

Risk assessment evaluates the results of the risk characterization and provides an interpretation of the magnitude of potential ecological risk and its significance. Risk assessment provides a context for information that may be used in risk decision-making. In this particular ERA, risk assessment evaluates the relative effectiveness in the scrubber installation in reducing potential ecological risk.

A number of assumptions that can lead to uncertainty are made in the assessment of the potential for adverse ecological impacts. Some of the sources of uncertainty in the ecological risk assessment are common to assessments of both the aquatic community and vertebrate receptors, while some are specific to each. The assumptions made in the ecological risk assessment were chosen to be conservative and protective. The overall effects of combining several of these conservative assumptions is to overestimate the potential for adverse ecological effects. A qualitative discussion of the major sources of uncertainty associated with the ecological risk assessment is presented below.

#### General Sources of Uncertainty

The aquatic risk assessment relied on chronic toxicity values to analyze the potential for ecological risk. Chronic toxicity values were used as benchmarks because it was assumed that aquatic life (water column and benthic species) would experience continuous, chronic exposure. Exposure in the aquatic environment is also likely to be continuous for benthic invertebrate species in the littoral sediments directly adjacent to the Milliken Station facility. However, fish species are generally transitory and are more likely to move within the lake, both vertically and horizontally. However, it was assumed that the fish were chronically exposed to epilimnetic mercury concentrations. Thus, the assumption of chronic exposure to epilimnion water may be realistic for the littoral sediment species, but will likely overpredict exposure for free-ranging surface water species.

The mammalian and avian receptors were assumed to spend their entire lives exposed to the modeled concentrations of mercury. This assumption overestimates exposure because it does not address movement of the representative species in and out of the area. For example, it was conservatively assumed that the bald eagles will consume virtually one hundred percent of their daily diet by feeding on aquatic organisms in Cayuga Lake for each breeding season of their lives. Although eagles move freely within the Finger Lakes Basin, the assessment assumed that the eagle would inhabit a nest near Milliken Station and would not feed outside of this area.

Similar conservative exposure assumptions were also made that would be likely to overestimate risk to mink such as the assumption of a complete fish diet. It is unlikely, because of winter ice cover, that the mink will be able to obtain its entire diet from fish from Cayuga Lake during the winter months.

A source of uncertainty in the application of the toxicity quotient method is the source of the toxicity data used in deriving the benchmark concentrations. The lowest data points among the available toxicity data were conservatively selected as the benchmark concentrations. The lowest data point observed in the laboratory, however, may not be representative of the actual toxicity that might occur in the environment. In establishing water quality criteria, for example, the U.S. EPA follows extensive guidelines in which toxicity data are screened so that questionable values are rejected, and geometric means are calculated to represent species mean, acute, and chronic values. Conversely, using the lowest reported toxicity data point as a benchmark concentration, as was done in this assessment, may be a very conservative approach, especially when there is a wide range in reported toxicity values for the relevant species. Differential species sensitivity to the compounds may result in these benchmarks underestimating or, more likely, overestimating potential acute and chronic toxicity for many aquatic organisms.

The dose-response values used for the vertebrate receptors were extrapolated from data on similar species because little direct dose-response information was available for the vole, shrew, or hawk. The extrapolation from laboratory species involved conservative assumptions; thus, it is likely that the dose-response values chosen will result in overestimates of the potential for adverse effects.

Another source of uncertainty exists in the prediction of the bioavailability of mercury from measured concentrations in the different media. For example, if the compound is bound to sediment or soil, it may not be bioavailable to the receptor; and the total concentration measured in the sediment or soil may be an overestimate of the amount of compound to which the receptor is actually exposed. Certain physical and compound characteristics of the aquatic ecosystem will affect the bioavailability and methylation rates of mercury. Some of these factors will vary depending on the season of the year. Temperature, pH, sorption to particles, dissolved oxygen, dissolved organic carbon content, and certain water quality parameters (e.g., calcium, sulfide) are some of the parameters that will affect the bioavailability and methylation of mercury. By choosing the lowest toxicity benchmark, it is likely that potential risks will be significantly overestimated.

Extrapolation of the potential for community, population, or ecosystem impacts from the examination of potential effects on individual animals of one or more representative species is a major source of uncertainty for both the aquatic and terrestrial analyses. The underlying assumption is that potential effects on one animal of a representative species are consistent with the effects on similar species and representative of the potential for effects on the particular ecosystem being investigated. Vole, shrew, mink, red-tailed hawk, and bald eagle were chosen to represent the potential for effects on mammals and

avians in the terrestrial ecosystem. The selection of each of these representative species as indicators of the ecosystem is one source of uncertainty in the risk assessment.

For the vertebrate receptors, the selection of these receptors overestimates potential ecosystem effects. The receptors were chosen based on their potentially higher exposures, resulting from trophic pathway (mink, hawk, eagle) or limited home range (vole, shrew). Thus, it is assumed that if these representative species are minimally affected, the potential for ecosystem-level effects are also unlikely. The effect of these assumptions is to overestimate the potential for adverse ecological effects to other species.

### Specific Sources of Uncertainty

In addition to the general source of uncertainty discussed above, other site-specific uncertainties were noted. Specific uncertainties associated with the Milliken Station ERA include the following:

- In general, the assumptions included in the screening level model are conservative assumptions. For instance, the bald eagle model assumed that approximately 99% of the eagle's diet consisted of Cayuga Lake fish. However, according to EPA (1993b), terrestrial mammals and avians typically make up approximately 20% of the eagle's diet. A similar assumption of maximal fish diet was made for the mink.
- Both TRUE and R-MCM are steady-state models which assume that environmental conditions are constant, when these factors are highly dynamic and incorporate daily, seasonal, and inter-annual variation.
- The use of TRUE and R-MCM to predict media mercury concentrations has considerable but unquantified uncertainty due to the large number of parameters and variables used in these models. Many of these input variables are estimated and assumed for Cayuga Lake and region. The effect of this uncertainty for the relative conservatism of the food web models is unknown. On the other hand, previous work with R-MCM has indicated excellent agreement between predicted predatory fish mercury tissue burden (0.276  $\mu\text{g MeHg/g wet wt}$ ) and those actually observed in lake trout (0.26  $\mu\text{g MeHg/g wet wt}$ ) captured in Cayuga Lake (Simonin, pers. comm).
- Terrestrial food web models were based on the use of maximum deposition rates in the southeast radian within 10 km. Since this is the maximum soil concentration, it provides a conservative estimate of potential ecological risk to terrestrial receptors.

## **SUMMARY AND CONCLUSIONS**

The results of the Milliken Station ERA for the pre-retrofit conditions indicate no potential ecological concern for any of the aquatic or terrestrial ecological receptors. For the aquatic receptors the highest risk was due to methylmercury in the sediment, but the HQ (0.0033) was two orders of magnitude below a level of concern. For the wildlife receptors the greatest risk was indicated for the top trophic predators in the aquatic pathway (i.e.,

mink (HQ = 0.07); bald eagle (HQ = 0.026)), but again below the level of concern. These results indicate that the pre-retrofit conditions do not lead to mercury emissions that have adverse impacts on the local environment.

The results of the Milliken Station ERA for the post-retrofit conditions also indicate no potential ecological concern for any of the aquatic or terrestrial ecological receptors. For the aquatic receptors the highest risk was due to methylmercury in the sediment, but the HQ (0.0033) was two orders of magnitude below a level of concern. For the wildlife receptors the greatest risk was indicated for the top trophic predators in the aquatic pathway (i.e., mink (HQ = 0.0043); bald eagle (HQ = 0.0015)), but again below the level of concern. These results indicate that the pre-retrofit conditions do not lead to mercury emissions that have adverse impacts on the local environment. Potential future ecological risks are approximately one order of magnitude less than those estimated for the pre-retrofit scenario.

**TABLE 5.6-1  
PREDICTED MEDIA CONCENTRATIONS AND RESPECTIVE SCREENING VALUES  
MILLIKEN STATION ERA**

Scenario	Mercury Form	Medium	Concentration (ppm)	Benchmark value (ppm)	Hazard Quotient	Exceed Benchmark?
Pre- Retrofit	Methyl Mercury	Surface Water	5.00E-09	3.00E-06	1.67E-03	No
		Sediment	5.00E-04	1.50E-01	3.33E-03	No
		Soil	NE		NC	
	Total Mercury	Surface Water	5.60E-08	1.30E-03	4.31 E-05	No
		Sediment	1.00E-03	1.50E-01	6.67E-03	No
		Soil	3.30E-12	3.00E-01 (p) 1.00E-01 (i)	1.10E-11 3.30E-11	No -
Post- Retrofit	Methyl Mercury	Surface Water	5.00E-10	3.00E-06	1.67E-04	No
		Sediment	5.00E-04	1.50E-01	3.33E-03	No
		Soil	-		NC	-
	Total Mercury	Surface Water	5.00E-09	1.30E-03	3.85E-06	No
		Sediment	5.00E-04	1.50E-01	3.33E-03	No
		Soil	3.53E-13	3.00E-01 (p) 1.00E-01 (i)	1.18E-12 3.53E-12	No

**Notes:**  
 NE = Not Estimated in models  
 NC = Not Calculated  
 (p) - Screening benchmark for plants.  
 (i) - Screening benchmark for invertebrates.

## **5.6.2 MULTIMEDIA HUMAN HEALTH AND ECOLOGICAL RISK ASSESSMENT FOR THE POTENTIAL WASTEWATER DISCHARGE OF THE NYSEG MILLIKEN STATION**

### **INTRODUCTION**

This study presents an assessment of the potential risks to human health and wildlife that could be associated with the discharge of wastewater from the flue gas desulfurization (FGD) system of NYSEG's Milliken Station into Cayuga Lake. The Total Risk of Utility Emissions (TRUE) model was used to calculate the potential human health risks and the environmental concentrations of mercury. The potential risks to wildlife due to mercury exposure were then calculated using a food web model.

### **FACILITY DESCRIPTION**

The NYSEG Milliken power station is located alongside Cayuga Lake in Lansing, New York. It is approximately 55 kilometers southwest of Syracuse, in the Finger Lakes Region of New York State. In 1995, a flue gas desulfurization (FGD) system was installed to control sulfur dioxide (SO<sub>2</sub>) emissions. The purpose of this study is to quantify the potential human health risks that would be associated with the discharge of the FGD wastewater into Cayuga Lake.

The FGD wastewater product was sampled for 27 chemicals (Janati, 1997). Polycyclic aromatic hydrocarbons (PAHS) and dioxins/furans were not sampled in the wastewater. Ten of the chemicals were not detected. Of the remaining 17 chemicals, 11 chemicals were included in the human health risk assessment (i.e., 7 chemicals were considered non-hazardous to human health; see Seigneur et al., 1998 for a discussion of the selection of chemicals to be included in the health risk assessment). Table 5.6-2 presents the potential discharge rates of these chemicals into Cayuga Lake. The largest discharge rate is that of hydrochloric acid (HCl). This discharge rate is consistent with the high concentration of HCl in the flue gas and the high solubility of HCl which transfers HCl from the flue gas to the FGD wastewater. Since the two units of the Milliken Station are identical, the discharge rates presented by Janati (1997) for Unit 2 were doubled. A correction by a factor of 0.88 was further made to account for the annual capacity of the power plant. Only one chemical (beryllium) that is carcinogenic through ingestion was detected in the wastewater. Chromium (VI) and some chemical forms of nickel are considered carcinogenic only through inhalation. Since these chemicals are non-volatile and are being discharged in a water body, their carcinogenic effects were not relevant to this health risk assessment.



**TABLE 5.6-2 CHEMICAL DISCHARGE RATES  
(ANNUAL - AVERAGE RATE FOR BOTH MILLIKEN STATION UNITS)**

<b>Chemical</b>	<b>Discharge Rate (mg/s)</b>
Beryllium	$9.31 \times 10^{-4}$
Cadmium	$5.32 \times 10^{-4}$
Chromium	$8.54 \times 10^{-3}$
Lead	$2.89 \times 10^{-3}$
Manganese	$2.22 \times 10^{-2}$
Nickel	$5.32 \times 10^{-2}$
Barium	$8.87 \times 10^{-1}$
Sulfate	$8.43 \times 10^{+2}$
Fluoride	$8.87 \times 10^{-1}$
HCl	$2.27 \times 10^{+4}$

## **RESULTS OF THE HUMAN HEALTH RISK ASSESSMENT**

### **Chemical Concentrations in Cayuga Lake**

The concentrations of the chemicals discharged with the wastewater were calculated for Cayuga Lake using the surface water model of TRUE. The simulation assumes that the chemicals are well mixed within the lake. Table 5.6-3 presents these chemical concentrations for the 11 chemicals that were detected in the wastewater discharge and included in the risk assessment. These concentrations are proportional to the discharge rates, and consequently, the largest concentration in the lake is that of HCl (0.8 mg/l).

### **Carcinogenic Health Effects**

As mentioned earlier, beryllium was the only chemical that was detected in the wastewater and which is carcinogenic through ingestion. The maximum excess cancer risk due to the wastewater discharge of beryllium is  $5.5 \times 10^{-9}$  (0.0055 per million). For comparison, the State of California requires public notification when the estimated carcinogenic risk exceeds 10 per million. Table 5.6-4 presents a breakdown of the calculated beryllium human dose by exposure route. About three-quarters of the beryllium dose is ingested with drinking water and about one quarter through fish consumption. Ingestion of water while swimming in the lake is a negligible exposure route.

### **Non-Carcinogenic Health Effects**

Table 5.6-5 presents a breakdown of the hazard index by chemical and exposure route (i.e., ingestion or dermal absorption). The hazard index (HI) is a measure of the potential noncarcinogenic health effects. If it is less than one, no adverse non-carcinogenic health

effects are anticipated. The total hazard index is 0.0024, i.e., significantly less than the threshold value of 1. Consequently, no adverse non-carcinogenic health effects are anticipated as a result of wastewater discharge to Cayuga Lake.

Hydrochloric acid (HCl) contributes 95% of the total non-carcinogenic health risk. Only 0.5% of the total risk is due to dermal absorption; 99.5% is due to ingestion.

Table 5.6-6 presents a breakdown of the calculated HCl human dose by exposure route. Ingestion of drinking water is the major exposure route for HCl.

**TABLE 5.6-3  
EXCESS CHEMICAL CONCENTRATIONS IN CAYUGA LAKE**

Chemical	Concentration (mg/l)
HCl	$7.96 \times 10^{-1}$
Sulfate	$2.96 \times 10^{-2}$
Barium	$3.11 \times 10^{-5}$
Fluoride	$3.11 \times 10^{-5}$
Nickel	$1.87 \times 10^{-6}$
Manganese	$7.79 \times 10^{-7}$
Chromium (VI)	$3.00 \times 10^{-7}$
Lead	$1.01 \times 10^{-7}$
Beryllium	$3.27 \times 10^{-8}$
Cadmium	$1.87 \times 10^{-8}$

**TABLE 5.6-4  
BERYLLIUM DOSE (MG/KG-DAY) BY EXPOSURE ROUTE**

Exposure Route	Dose	Contribution (%)
Drinking Water	$9.33 \times 10^{-10}$	73.7
Swimming in Water	$1.16 \times 10^{-12}$	0.1
Fish Consumption	$3.31 \times 10^{-10}$	26.2
Total	$1.27 \times 10^{-9}$	100.0

**TABLE 5.6-5  
NON-CARCINOGENIC HAZARD INDEX BY CHEMICAL AND EXPOSURE ROUTE  
(LISTED IN ORDER FROM LARGEST HI TO SMALLEST HI)**

Chemical	Ingestion		Dermal Absorption		Total
	HI	%	HI	%	
HCl	$2.28 \times 10^{-3}$	99.7	$6.31 \times 10^{-6}$	0.3	$2.28 \times 10^{-3}$
Sulfate	$8.62 \times 10^{-5}$	99.7	$2.34 \times 10^{-7}$	0.3	$8.64 \times 10^{-5}$
Barium	$1.43 \times 10^{-5}$	99.8	$3.52 \times 10^{-8}$	0.2	$1.43 \times 10^{-5}$
Lead	$1.29 \times 10^{-5}$	99.9	$1.87 \times 10^{-8}$	0.1	$1.29 \times 10^{-5}$
Manganese	$7.53 \times 10^{-7}$	14.6	$4.41 \times 10^{-6}$	85.4	$5.16 \times 10^{-6}$
Nickel	$5.01 \times 10^{-6}$	99.9	$7.40 \times 10^{-9}$	0.1	$5.02 \times 10^{-6}$
Cadmium	$2.68 \times 10^{-6}$	99.9	$2.96 \times 10^{-9}$	0.1	$2.68 \times 10^{-6}$
Chromium (VI)	$2.23 \times 10^{-6}$	99.8	$4.75 \times 10^{-9}$	0.2	$2.23 \times 10^{-6}$
Beryllium	$2.53 \times 10^{-7}$	99.8	$5.18 \times 10^{-10}$	0.2	$2.54 \times 10^{-7}$
Fluoride	$9.07 \times 10^{-9}$	99.7	$2.47 \times 10^{-10}$	0.3	$9.09 \times 10^{-9}$
Total	$2.40 \times 10^{-3}$	99.5	$1.10 \times 10^{-5}$	0.5	$2.41 \times 10^{-3}$

**TABLE 5.6-6  
HCl DOSE (MG/KG-DAY) BY EXPOSURE ROUTE**

Exposure Route	Dose	Contribution (%)
Drinking Water	$1.29 \times 10^{-2}$	99.88
Swimming in Water	$1.61 \times 10^{-5}$	0.12
Total	$1.29 \times 10^{-2}$	100.00

**RESULTS OF THE ECOLOGICAL RISK ASSESSMENT FOR WASTEWATER DISCHARGES OF MERCURY**

**Introduction**

This ecological risk assessment was conducted to evaluate potential risks to ecological receptors exposed to mercury through wastewater discharges from the flue gas desulfurization (FGD) system at Milliken Station into Cayuga Lake. Mercury was selected for this ecological assessment because it has been identified as a chemical of concern for ecological impacts in the Clean Air Act Amendments of 1990. Mercury loading to the lake in the wastewater discharge was estimated to be 1920 µg HG(II) per day. This estimate corresponds to half the detection limit of mercury concentration in the effluent, since mercury was not detected in the wastewater (Janati, 1997). The media of interest

for this discharge source are Cayuga Lake surface water and sediment. Bioaccumulation of mercury in the food chain is the primary exposure pathway of concern; however, direct exposure to and ingestion of surface water and sediment have also been evaluated as exposure pathways. Mercury exposures evaluated here are incremental, and therefore, represent discrete exposures beyond those for atmospheric mercury emissions due to stack releases evaluated in the Milliken Station ecological risk assessment (ERA) (Mitchell et al., 1998), hereafter referred to as the ERA report.

The ecological risk assessment approach and methods are comparable to those used in the ecological risk assessment of the stack emissions. More detailed discussion of these methods and specific risk assessment tools are provided in the Milliken Station ERA report. Two ecological risk assessment approaches are utilized as follows:

- Predicted mercury concentrations in sediment and surface water are compared with ecological effects-based screening values; and
- A food web exposure model was run to evaluate potential risks to piscivorous wildlife.

The following sections briefly discuss the development of exposure point concentrations, sediment screening, and food web modeling results.

### **Exposure Point Concentrations**

Table 5.6-7 presents the mercury exposure point concentrations in surface water, sediment, and fish resulting from wastewater loadings to Cayuga Lake predicted using the Regional Mercury Cycling Model (R-MCM). The wastewater discharge was modeled as a point source to the lake and mixing was assumed to occur instantaneously. Other assumptions used in modeling these exposure point concentrations are described in the ERA report. The R-MCM output will not report concentrations less than  $0.001 \mu\text{g}/\text{m}^3$  and the wastewater loading results in media concentrations less than this value. Therefore, higher wastewater loadings (up to five orders of magnitude higher) were modeled and plotted against predicted media concentrations. A regression was performed on these data points to extrapolate down to predicted media concentrations for the actual wastewater loading concentrations.

### **Benchmark Screening of Media Concentrations**

Table 5.6-8 summarizes the screening of predicted surface water and sediment mercury concentrations against ecological effects-based screening benchmarks. The selection of screening values is discussed in the ERA report. Predicted concentrations of methyl and total mercury in both surface water and sediment are substantially lower than their respective screening benchmarks. Calculated hazard quotients (HQ's) are all less than one, ranging from  $3.54 \times 10^{-8}$  for total mercury in surface water to  $3.87 \times 10^{-6}$  for total mercury in sediment. Based on these HQ's, no significant potential risk exists to aquatic receptors from mercury in wastewater discharges.

**TABLE 5.6-7  
EXPOSURE POINT CONCENTRATIONS USED IN FOOD WEB MODELS  
CONTRIBUTIONS FROM WASTEWATER DISCHARGE, MILLIKEN STATION, LANSING, NY**

Mercury Species	Medium	Concentration	Units
Methyl Mercury	Surface Water <sup>1</sup>	1.94x10 <sup>-12</sup>	mg/l
	Sediment <sup>1</sup>	7.00x10 <sup>-8</sup>	mg/kg dry weight
Total Mercury	Surface Water <sup>1</sup>	4.07x10 <sup>-11</sup>	mg/l
	Sediment <sup>1</sup>	5.80x10 <sup>-7</sup>	mg/kg dry weight
	Prey Fish <sup>1</sup>	4.26x10 <sup>-6</sup>	mg/kg wet weight for 3-year old fish
	Predatory Fish <sup>1</sup>	1.29x10 <sup>-5</sup>	mg/kg wet weight for 5-year old fish

Notes:  
1: Value is below model output limit and was estimated using logarithmic regression.

**TABLE 5.6-8  
CONCENTRATIONS AND SCREENING VALUES FOR ALL MEDIA  
CONTRIBUTIONS FROM WASTEWATER DISCHARGE, MILLIKEN STATION, LANSING, NY.**

Mercury Species	Medium	Concentration (ppm)	Benchmark value (ppm)	Hazard quotient	Exceed Benchmark?
Methyl Mercury	Surface Water	1.94x10 <sup>-12</sup> (1)	3.00x10 <sup>-6</sup> (2)	6.47x10 <sup>-7</sup>	No
Mercury	Sediment	7.00x10 <sup>-8</sup> (1)	1.50x10 <sup>-1</sup> (3)	4.67x10 <sup>-7</sup>	No
Total Mercury	Surface Water	4.61x10 <sup>-11</sup> (1)	1.30x10 <sup>-3</sup> (4)	3.54x10 <sup>-8</sup>	No
Mercury	Sediment	5.80x10 <sup>-7</sup> (1)	1.50x10 <sup>-7</sup> (2)	3.87x10 <sup>-6</sup>	No

Notes:  
1. Values were estimated by incrementally varying the wastewater mercury contribution until outputs were detected by R-MCM.  
2. Methylmercury SCV; Suter and Mabrey, 1994 as cited in U.S. EPA, 1996  
3. Total mercury ER-L; Long and Morgan, 1990 as cited in NYSDEC, 1993  
4. Inorganic mercury SCV; Suter and Mabrey, 1994 as cited in U.S. EPA, 1996

SCV - Secondary Chronic Value  
ER-L - Effects Range-Low

### Food Web Model Exposures

The bald eagle and mink were selected as sensitive ecological receptors for evaluation in the food web model as described in the ERA report. Tables 5.6-9 and 5.6-10 present the food web model exposure parameters and toxicity reference values for these two receptors, respectively. Tables A-1 through A-4 in Appendix A of the report present the food web modeling inputs and calculations. Calculated HQ's for the bald eagle and mink exposed to both forms of mercury (total and methyl) are all less than one, ranging from 5.39x10<sup>-5</sup> to 2.70x10<sup>-6</sup> for the mink exposed to methyl and total mercury, respectively (table 5.6-11). As in the ecological risk assessment for the stack emissions, direct ingestion of surface water and sediments represent exposure pathways associated with minimal potential risk. The ingestion of aquatic organisms contributed almost 100% of

the potential risk to both receptors. However, the calculated HQ for both the bald eagle and the mink reveal no significant potential risks to either receptor from mercury discharged to Cayuga Lake in the wastewater effluent from the plant.

### **Conclusions**

Based on this ecological risk assessment, the discharge of mercury in wastewater effluent from the Milliken Station to Cayuga Lake poses no significant potential risks to aquatic receptors or piscivorous wildlife.

TABLE 5.6-9  
 ESTIMATED EXPOSURE PARAMETERS FOR WILDLIFE RECEPTORS IN TIER 1 FOOD WEB MODELS  
 CONTRIBUTIONS FROM WASTEWATER DISCHARGE, MILLIKEN STATION, LANSING, NY.

Receptor Species	Body Weight (kg)	Assumed Diet Components		Food Ingestion Rate (kg-day)	Weighted Food Consumption Rate [a] (kg/day)	Water Intake Rate (l-day)	Exposure Duration (unitless)	Home Range (hectares)	Home Range (acres)
		Aquatic Organisms	Sediment						
Mink <i>Mustela vison</i>	1 [c]	95% [d]	5% [e]	0.22 [f]	0.209 Aquatic Org 0.011 Sediment	0.099 [g]	1 [b]	14.1 [h]	34.8 [h]
Bald Eagle <i>Haliaeetus leucocephalus</i>	4.5 [i]	99% [j]	1% [j]	0.585 [k]	0.579 Aquatic Org 0.005 Sediment	0.162 [l]	0.75 [b]	3500 [m]	8649 [m]

- [a] (Food Ingestion Rate) x (Assumed Diet for Exposure Assessment)
- [b] All receptors are assumed to be present year-round, with the exception of the bald eagle (assumed present 9 months).
- [c] Opreko, et al. (1994) as cited in Great Lakes Water Quality Initiative criteria documents (USEPA, 1995)
- [d] From Michigan study (USEPA, 1993a)
- [e] Estimated from Beyer, et al. (1994)
- [f] Adult male year-round, estimated (USEPA, 1993a)
- [g] Adult male water ingestion rate (USEPA, 1993a)
- [h] Average of adult females in Montana riverine habitat study (USEPA, 1993a)
- [i] Average summer weights of juvenile male and female bald eagles in Alaska study (USEPA, 1993a)
- [j] Bald eagle conservatively estimated to consume only aquatic organisms. Sediment ingestion estimated.
- [k] Average weights of *H. leucocephalus* in Connecticut free-flying study (USEPA, 1993a)
- [l] Estimated average of male and female adult *H. leucocephalus* (USEPA, 1993a)
- [m] Mean home range of breeding pair in the spring in an Arizonan study (USEPA, 1993a)

**TABLE 5.6-10  
DERIVATION OF TOXICITY REFERENCE VALUES FOR MERCURY  
CONTRIBUTIONS FROM WASTEWATER DISCHARGE, MILLIKEN STATION, LANSING, NY**

Constituent	Test Species	Body Weight (kg)	Chronic Test Dose Weight (mg/kg-day)	Reference	Scaling Factor <sup>4</sup>		TRV	
					Mink	Bald Eagle	Mink	Bald Eagle
Mercury (inorganic)	Mink	1	1.00	1	1.00	1.00	1.00	4.5x10 <sup>-1</sup>
	Japanese quail	1		1				
Mercury (methylmercury)	Mink	1	5.00x10 <sup>-2</sup>	2	1.00	1.00	5.00x10 <sup>-2</sup>	6.4x10 <sup>-2</sup>
	Mallard	1	6.4x10 <sup>-2</sup>	3				

<sup>1</sup> NOAEL values used for the derivation of TRVs for the receptor species from Sample et al., 1996

<sup>2</sup> NOAEL based on a study by Wobeser et al. (1976) cited in EPA Mercury Report to Congress Draft, 1997

<sup>3</sup> LOAEL value used for the derivation of TRVs for the receptor species from Sample et al., 1996

<sup>4</sup> Scaling factors calculated as follows:

Mammals: (Body weight of test species/Body weight of Receptor)<sup>0.25</sup>

Birds: (Body weight of test species/Body weight of Receptor)<sup>0</sup>

TRV = (Chronic Test Dose) x (Scaling factor)

Species	Body Weight
Bald Eagle <i>Haliaeetus leucocephalus</i>	4.5 kg
Mink <i>Mustela vison</i>	1 kg



**TABLE 5.6-11**  
**HAZARD QUOTIENTS RESULTING FROM FOOD WEB MODELS**  
**CONTRIBUTIONS FROM WASTEWATER DISCHARGE, MILLIKEN STATION**  
**LANSING, NY.**

<b>Mercury Species</b>	<b>Mink</b>	<b>Bald Eagle</b>
Methylmercury	$5.39 \times 10^{-5}$	$1.95 \times 10^{-5}$
Total mercury	$2.70 \times 10^{-6}$	$2.77 \times 10^{-6}$

The intent of this program was to analyze and characterize the liquid and solid wastes generated by Milliken Station after the CCTD had been installed. The analysis was to include physical, chemical and mineralogical composition of the wastes as well as the leachate they generated. This information was to be used to run EPRI leachate and plume migration programs such as MYGIRT, FOWL and PCTRANS.

As part of this program NYSEG compared the predictions of three EPRI leachate and plume migration programs, MYGIRT, FOWL and PCTRANS, with actual leachate data from the Milliken Ash landfill. NYSEG's preliminary findings are summarized below.

At the time of publication of this Project Performance and Economics Report the results of the Land and Water Quality Program had not been published. When the results of this program become available they will be the subject of a Topical Report.

#### 5.7.1 EVALUATION OF THE EPRI FOWL CODE AS APPLIED AT MILLIKEN ASH

##### DISPOSAL FACILITY

FWL is a fossil fuel waste leaching program that calculates the quantities and aqueous concentrations of selected inorganic constituents found in fossil fuel combustion wastes. The code was based on a critical review of the literature, laboratory characterization of waste samples from several power plants, and field data from a FGD sludge disposal site and a fly ash test landfill.

Required inputs are: bulk chemistry of the coal combustion byproduct and precipitation, physical properties of the byproduct, geometry of the waste disposal unit, and infiltration information.

##### GENERAL COMMENTS

- Model needs to be updated to meet current CPU and operating systems especially a user interface compatible with Windows.
- User had difficulties loading program, especially climatological data for the HELP module. This appears to be caused again by operating system incompatibility.

##### APPLICATION TO MILLIKEN ASH

For the Milliken Ash application, the landfill was modeled as a rectangular 38,890 square meter area with an average waste thickness of 10 meters. Fly ash porosity has been calculated as 0.30 (unitless). The net precipitation infiltration during filling was calculated as 48.3 cm/year. A cap was placed on the landfill and vegetated in 1987 after three years of operation which reduced the net precipitation to 17.2 cm/year.

Bulk chemistry of the fly ash was available from NYSEG's Environmental Laboratory records and a study of Milliken Station fly ash completed in 1996. A review of the data

indicates that the coal ash bulk chemistry has changed significantly over the last several years. Bulk chemistry of the rainwater in the Milliken Ash area was available in a report completed by Cornell University.

FOWL was run using a 20 year time interval, from 1983 to 2003. The FOWL predictions are compared with actual leachate analyses from the Milliken Ash underdrain. Results are summarized below:

**TABLE 5.7-1  
COMPARISON OF PREDICTED AND ACTUAL  
LEACHATE CONCENTRATIONS OF INORGANIC CONSTITUENTS**

Parameter	FOWL Prediction	Actual Leachate
pH	6.5 - 10.0 S.U.	7.1 - 8.1 S.U.
Total Dissolved Solids	2485.2 - 4385.9 mg/l	2400 - 3860 mg/l
Calcium	442.5 - 532.4 mg/l	440 - 606 mg/l
Barium	0.015 - 0.016 mg/l	0.022 - 0.30 mg/l
Strontium	8.9 - 10.6 mg/l	NA
Sulfate	1938 - 3931 mg/l	996 - 2800 mg/l
Cadmium	0.188 - 0.404 mg/l	<0.005 - 0.046 mg/l
Chromium	0.004 - 0.011 mg/l	<0.005 - 0.032 mg/l
Copper	0.026 - 0.576 mg/l	<0.01 - 0.19 mg/l
Arsenic	0.033 - 0.172 mg/l	<0.005 - 0.014 mg/l
Nickel	0.020 - 0.079 mg/l	0.19 - 0.35 mg/l
Selenium	0.037 - 0.215 mg/l	<0.01 - 0.24 mg/l
Molybdenum	0.866 - 1.750 mg/l	NA
Carbonate	1.03 - 2.15 mg/l	NA

As illustrated by the table, FOWL was relatively accurate predicting the leachate concentrations of pH, TDS, calcium, sulfate, chromium, copper, and selenium. FOWL tended to be high in its estimation of cadmium and arsenic concentrations and low in its estimation of barium and nickel concentrations.

Errors in FOWL predictions of concentrations are likely caused by a variety of factors. First and foremost, FOWL assumes a homogeneous waste unit which is not an accurate assumption at Milliken Ash where the leachate is generated by fly ash produced from coals with different chemistry landfilled over a 15 year period. A corollary to this factor is that there is a limited amount of total and TCLP data on a few different samples of coal ash which cannot encompass the wide variety of coal ash that has been landfilled at the Milliken facility.

A second factor is that ash is continuously being landfilled at the facility so that the ash ranges in age from 15 year old weathered ash to new ash. This impacts the leachate quality which would cause the actual leachate quality to significantly vary from the predicted values.

## CONCLUSIONS

FWL produced fair results when applied to Milliken Ash. Ease of use was also considered fair especially considering the now lagging user interface when compared to other programs that have been updated to a Windows environment.

Overall, FOWL is not considered applicable to the Milliken Ash Disposal Facility since the landfill is already constructed with a liner and a leachate collection system. Predicted leachate chemistry of the present or future leachate produced at the facility is not necessary since an actual analysis is performed on the leachate on a quarterly basis as required in the solid waste operating permit for the site.

However, for a new facility, FOWL would be much more applicable and could aid in selecting an appropriate design for the anticipated landfill permitting and construction, especially with the HELP module.

### 5.7.2 EVALUATION OF THE EPRI PCTRANS CODE AS APPLIED AT MILLIKEN ASH DISPOSAL FACILITY

PCTRANS is a finite element ground water flow and transport model for microcomputers. It is used in predicting ground water flow and can be coupled with a solute transport model.

#### GENERAL COMMENTS

- Model needs to be updated to meet current CPU and operating systems especially a user interface compatible with Windows.
- Due to operating system incompatibilities, user had several problems with PCTRANS such as inability to modify finite element grid property files and CPU lock up during grid analysis.
- The finite element grid editor was very difficult to use and would not allow minor modifications to a previously developed grid without starting over at the beginning.
- User guide inadequately written and poorly printed. The user guide should have more discussion of user inputs and use of triangular elements.
- The entire PCTRANS package seems to be "cobbled" together. Should be more seamless when moving from one module to another.

#### APPLICATION TO MILLIKEN ASH

Despite repeated runs and the frustration of attempting to modify the grid properties and boundary conditions, PCTRANS could not converge to the known flow conditions at the site.

## **CONCLUSIONS**

PCTRANS produced poor results when applied to Milliken Ash. Ease of use was also poor but could potentially benefit from an update to the Windows environment.

PCTRANS is considered not applicable to the Milliken Ash Disposal Facility since the model could not converge to the known flow conditions at the site. Perhaps with an improved user interface for grid development/editing and boundary condition input, more runs would have been performed in order to "tweak" the inputs and get a reliable output.

### **5.7.3 EVALUATION OF THE EPRI MYGRT CODE AS APPLIED AT MILLIKEN ASH DISPOSAL FACILITY**

MYGRT is a ground water solute transport model for microcomputers based on the quasi-analytical solution to the advection-dispersion-retardation-decay equation. It is used in predicting ground water solute concentrations for reactive and decaying organic and reactive and non-reactive inorganic substances.

#### **GENERAL COMMENTS**

- Model needs to be updated to meet current CPU and operating systems especially a user interface compatible with Windows.
- Documentation is good, especially the various case studies which apply MYGRT to a variety of situations encountered by utilities.

#### **APPLICATION TO MILLIKEN ASH**

MYGRT was used to simulate sulfate migration at Milliken Ash Disposal Facility. Sulfate is the best parameter to monitor the impact of Milliken Ash landfill on ground water quality. It occurs at relatively high concentration in the coal ash leachate, it is not prone to reactions involving ion exchange, and it is not significantly retarded by a soil matrix (Retardation coefficient of 1.0). Background concentration of sulfate averages 75 mg/l.

The landfill was modeled using a 2-dimensional vertical cross-section since the source area is wide as compared to downgradient distance. Required inputs include the longitudinal dispersion coefficient calculated at 480 M<sup>2</sup>/yr and the transverse dispersion coefficient of 4.8 M<sup>2</sup>/yr. Seepage velocity is calculated at 24 M/yr. The saturated aquifer thickness is 17 meters. Operational history began in 1984 and was continued to 2050 to examine steady state conditions.

The two methods for modeling the source, initial concentration in aquifer and leachate influx generated in the waste unit, were applied. For the waste unit leachate influx application, the landfill was modeled as a rectangular 38,890 square meter area. The leachate concentration of sulfate is 1800 mg/l. The aquifer porosity has been calculated as 0.30(unitless). The net precipitation infiltration was calculated as 17.2 cm/year and aquifer penetration depth of leachate was estimated at two meters. Initial concentration in the aquifer was calculated as 1200 mg/l.

MYGRT was relatively accurate at predicting the downgradient concentration of sulfate at Milliken Ash using either the influx or initial concentration method of source modeling. Monitoring well 9114, located approximately 185 meters from the downgradient edge of the clay lined landfill has occasionally exhibited elevated levels of sulfate (225 - 372 mg/l in 1997; mean value of 299 mg/l) which MYGRT accurately predicted.

Unfortunately, there is a synthetically lined portion of the landfill between the clay lined landfill and the monitoring well which precludes sampling the ground water between the landfill and the well and, therefore, prevents evaluating the accuracy of MYGRT predictions closer to the clay lined landfill.

The time interval was extended and shows limited expansion, if any, of the sulfate plume and, therefore, a reduced chance of further downgradient ground water degradation.

## CONCLUSIONS

MYGRT produced good results when applied to Milliken Ash. Ease of use was also considered good but would benefit from an update to the Windows environment. Graphics could be enhanced with an upgrade of printer options so that newer color inkjet or laser printers could be used.

MYGRT is considered applicable to the Milliken Ash Disposal Facility and likely could be used in assessing occasional elevated levels of sulfate in the downgradient well at the facility. NYSEG has previously used MYGRT in evaluating inorganic substance migration at its Kingh Station Solid Waste Disposal Area and organic compound migration at some of its former manufactured gas plant sites with good results.

## **5.8 MILLIKEN BY-PRODUCT UTILIZATION STUDIES**

The principal products covered under this program included flyash, calcium chloride and gypsum.

Flyash, which is marketed as concrete additive, can be adversely affected by the installation of the Low NO<sub>x</sub> Concentric Firing System (LNCFS) and the Selective Non-Catalytic Reduction (SNCR) process. Increased carbon and ammonia concentrations can result in unmarketable ash. One objective of the By-Product Utilization Study was to analyze flyash both pre- and post- LNCFS/SNCR installation to determine impacts on the sale of ash due to changes in ash composition. Two reports were planned addressing different aspects of flyash marketability. One report was to evaluate the effects of LNCFS operation on flyash loss-on-ignition (LOI). Another was to evaluate effects of various ammonia concentrations on the marketability of flyash. The report evaluating the effects of LNCFS operation on flyash loss-on-ignition (LOI) is summarized below. The report of the impact of ammonia on flyash was to be based on data generated by the NO<sub>x</sub>OUT@ SNCR demonstration at Seward Station. Problems with the demonstration program at Seward precluded completion of this portion of the study.

Two new by-products were generated as a result of the operation of the Flue Gas Desulfurization (FGD) system: gypsum and calcium chloride brine. Separate reports for each by-product cover include surveys and market assessments of potential usage of these products in the United States as well as cost assessments and design considerations associated with operating experience for their handling and conditioning. These reports are summarized below.

### **5.8.1 IMPACT OF LOW-NO<sub>x</sub> BURNERS ON UTILIZATION OF FLY ASH**

The following is a summary of the report entitled "Milliken Clean Coal Technology Demonstration Project Impact of Low-NO<sub>x</sub> Burners on Utilization of Fly Ash." The report was authored by CONSOL, Inc. Copies are available from DOE upon request.

#### **ABSTRACT**

Daily data on fly ash quality and NO<sub>x</sub> emissions gathered over a five-year (1992-1996) period from the Milliken Station demonstrated that a 39% reduction in NO<sub>x</sub> was achieved using LNCFS-3 low NO<sub>x</sub> burners while producing a fly ash meeting the stringent NYDOT LOI requirement of less than 4%.

During the two years directly following the installation of low-NO<sub>x</sub> burners on Unit 1 and Unit 2, 91% to 92% of the fly ash produced at Milliken was sold into the high value cement replacement market.

#### **BACKGROUND**

As part of the Clean Coal Technology Demonstration Project at Milliken Station, NYSEG installed low NO<sub>x</sub> Concentric Firing System Level 3 (LNCFS-3) burners on Unit 1 and

Unit 2. To allow the station to remain on line at 50% of capacity, the burner conversions for the two units were done at different times. Unit 1 went down on March 26, 1993 and started up again on July 31, 1993. Evaluation and guarantee testing for the new burners was completed on March 15, 1994. Unit 2 was shut down on June 17, 1994 and restarted on December 13, 1994. Guarantee testing of the Unit 2 burner system was completed on August 15, 1995.

The published results from the LNCFS-3 test program showed that over the testing periods (60-70 days), the LNCFS-3 system could achieve 35+% NO<sub>x</sub> reduction while maintaining a fly ash LOI of less than 4%. This LOI value allowed NYSEG to continue to sell Milliken ash as a cement replacement.

## STUDY OBJECTIVE

The objective of this study was to confirm over a long period of time the impact which the LNCFS-3 low NO<sub>x</sub> burner retrofit had on the quality of fly ash produced.

## DATA ACQUISITION

The LOI value of daily samples taken by the ash marketer was used as the data source for the long-term fly ash quality comparison. This specific LOI value governed what the ash marketer would do with a particular day's ash and, therefore, represents the final word on ash quality. An LOI value of 4% or higher would dictate that the ash go to the landfill, while a value of 4% or less would allow it to go to the product silo. The daily LOI values were averaged by month. The LOI monthly average was the variable used in this study to show the fluctuation of fly ash quality with time.

As an indication of the general quality of the Milliken fly ash, two samples were taken from Unit 2 (one before and one after burner conversion) and analyzed by ASTM protocol C618 (cement replacement). These data will allow comparison with ash produced at other stations.

The daily values of NO<sub>x</sub> emissions (30-day rolling average) for the two units were averaged individually and the monthly values used to monitor the NO<sub>x</sub> emissions from the station.

## DISCUSSION

### NO<sub>x</sub> Emissions

Table 5.8.1-1 contains the monthly average from August 1992 through December 1996 for the NO<sub>x</sub> emissions for Unit 1 and Unit 2. The NO<sub>x</sub> was measured in each of the stacks independently, namely, Unit 1 and Unit 2. Figures 5.8.1-1 and 5.8.1-2 are plots of NO<sub>x</sub> versus time over the five-year period for Unit 1 and Unit 2.

To allow for the installation of the LNCFS-3 system, Unit 1 was shut down March 26, 1993. The unit was started up on July 31, 1993 and evaluation testing was completed on



March 15, 1994. Unit 2 went down June 17, 1994 and was put on line December 13, 1994. The burner guarantee testing for Unit 2 was completed on August 15, 1995.

Both graphs show that the NO<sub>x</sub> emissions decreased after the LNCFS-3 burner systems were installed. The specific amount of NO<sub>x</sub> reduction depends on what cut off dates are assumed for the new burners being optimized. The conclusion in the report completed earlier as part of the CCT-4 burner test program at Milliken was: "The achievable annual NO<sub>x</sub> emissions, estimated using long-term measurements, were 0.61 lb/MM Btu for Unit 2 baseline, and 0.39 lb/MM Btu for Unit 1 LNCFS-3." These results gave a 36% NO<sub>x</sub> reduction for the 60-day test.

This study assumed that Unit 1 burners were lined out by March 1994 and that the Unit 2 system was fined out by March 1995. The average of NO<sub>x</sub> emissions from these dates to December 1996 is 0.37 lb/MM Btu for both units (standard deviation of 0.06 for Unit 1 and 0.08 for Unit 2). Based on a NO<sub>x</sub> emissions rate of 0.61 lb/MM Btu before burner conversion, the results demonstrate that the LNCFS-3 burner system allowed Milliken to achieve a 39% reduction in NO<sub>x</sub> over extended periods (34 months for Unit 1 and 22 months for Unit 2) of time.

### **Ash Quality**

In the recent past, the fly ash produced at Milliken met the NYDOT specification for cement replacement, a high value utilization option. NYDOT's specification requires ash to have an LOI value of less than 4% in addition to passing the ASTM C-316 protocol. This LOI requirement is one of the most stringent in the USA. NYSEG worked hard in marketing the Milliken ash and in 1993 sold 91% of the ash produced, compared to 83% sold in 1992.

It was assumed that the ash property most influenced by the use of low NO<sub>x</sub> burners was the LOI. To confirm this assumption, two ash samples were obtained, each sample represented a two-day period before and after the low NO<sub>x</sub> burner conversion. The samples were taken from Unit 2 when firing Bailey coal. The as-received coal analysis and date when the ash samples were taken are shown in the following table.

Date	Before Conversion 11/19-20/93	After Conversion 10/17-18/95
Ash	7.23%	8.6%
Sulfur	1.8%	1.75%
H <sub>2</sub> O	6.6%	6.5%
Heating Value, Btu/lb	12,992	13,100

The two ash samples were processed through the suite of tests required by the ASTM C618 protocol. Both fly ash samples met all ASTM specifications for use as a mineral admixture in Portland cement concrete. Except for particle size, there was no substantial difference in the chemical compositions or the physical properties of the two fly ash samples. Appendix A is the report by Dr. M.M. Wu giving the detailed results of the C618 testing.

Table 5.8-1-2 shows the LOI monthly averages for the fly ash from Unit 1 and Unit 2 from January 1992 through December 1996. The average, based on the dates assumed for lined out burner conditions in the NO<sub>x</sub> emission analysis, LOI values, and standard deviation are shown in the table below.

	Unit 1	Unit 2
LOI % <sup>1</sup> Std Dev	0.37	0.41
Before Burner Conversion: 3.32	0.37	3.21
After Burner Conversion: 3.57	0.34	2.92
<sup>1</sup> Averaged: March 1994 to December 1996		
<sup>2</sup> Averaged: August 1995 to December 1996		

The results in this table demonstrate that "on spec" fly ash LOI < 4% was produced after the LNCFS-3 system was installed and tuned.

Figures 5.8-1-3 and 5.8-1-4 graphically show ash LOI as a function of time for Unit 1 and Unit 2, respectively. The graphs confirm that the new burners can achieve a 39% NO<sub>x</sub> reduction and produce fly ash which meets the NYDOT requirements for cement replacement in road construction.

### Ash Sales

The final data obtained for this study were the fly ash sales figures for Milliken, NYSEG supplied the following information on the fly ash sales from Milliken.

Year	Percent Ash Sold
1992	83
1993	91 Unit 1 LNCFS-3 on line 7/31
1994	93 Unit 2 LNCFS-3 on line 12/13
1995	92
1996	91

Sales information is the ultimate measure for fly ash quality. The sales figure of 90%+ strongly confirms the conclusion that the fly ash remained a high quality product following the burner conversion which gave a 39% reduction in NO<sub>x</sub>.

**TABLE 5.8.1-1  
NO<sub>x</sub> EMISSIONS  
(MONTHLY AVERAGE)—LB/MM BTU**

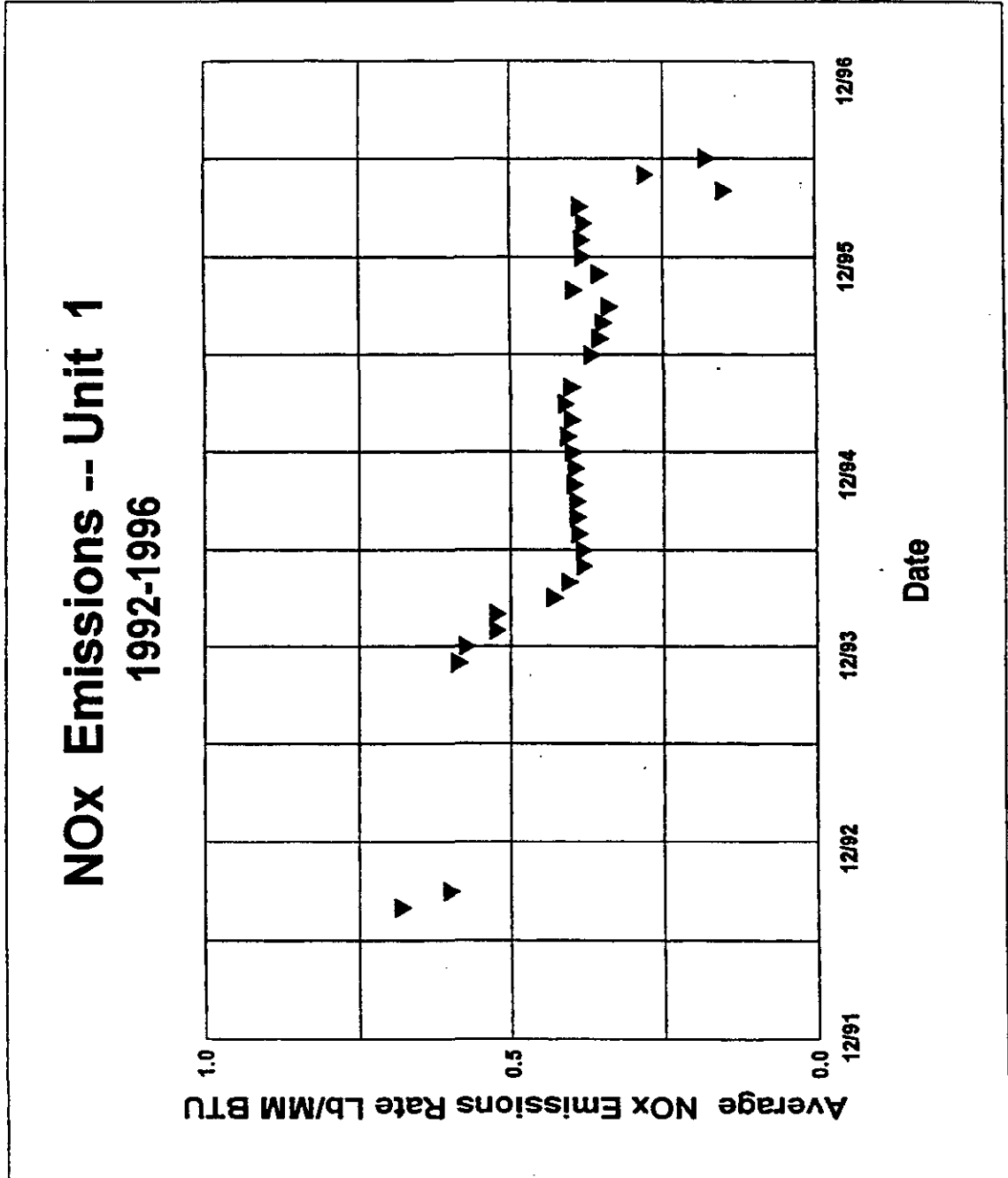
Date	Unit 1	Unit 2
8/92	0.68	0.69
9/92	0.60	0.65
10/92	0.59	0.57
11/92	0.57	0.54
12/92	0.52	0.56
1/93		
2/93		
3/93		
4/93		
5/93		
6/93		
7/93		
8/93		
9/93		
10/93		
11/93	0.59	0.57
12/93	0.57	0.54
1/94	0.52	0.56
2/94	0.52	0.54
3/94	0.43	0.57
4/94	0.41	0.59
5/94	0.38	0.52
6/94	0.38	0.60
7/94	0.39	
8/94	0.39	
9/94	0.39	
10/94	0.40	
11/94	0.39	
12/94	0.40	0.43
1/95	0.41	0.68
2/95	0.40	
3/95	0.41	0.32
4/95	0.40	0.38
5/95		0.39
6/95	0.37	0.38
7/95	0.35	0.36
8/95	0.35	0.36
9/95	0.34	0.15
10/95	0.40	0.39
11/95	0.35	0.39
12/95	0.38	0.39
12/95	0.38	0.39
1/96	0.38	0.39
2/96	0.38	0.39
3/96	0.39	0.41
4/96	0.15	0.35
5/96	0.28	0.37
6/96	0.18	0.38
7/96		0.37
8/96	0.09	0.37
9/96	0.39	0.37
10/96		0.37
11/96		0.39
12/96		0.38

TABLE 5.8.1-2  
LOI (MONTHLY AVERAGE)

UNIT 1	UNIT 2	Standard Dev.	Standard Dev.
3.29	2.63	0.40	0.40
2/92	2.61	0.35	0.35
3/92	2.79	0.49	0.49
4/92	3.22	0.79	0.79
5/92	3.02	0.63	0.63
6/92	3.25	0.46	0.46
7/92	3.05	0.56	0.56
8/92	3.44	0.31	0.31
9/92	2.89	0.77	0.77
10/92	3.35	0.44	0.44
11/92	2.03	0.56	0.56
12/92	2.75	0.63	0.63
1/93	3.64	0.36	0.36
2/93	3.65	1.01	1.01
3/93	3.43	0.76	0.76
4/93	3.29	0.71	0.71
5/93	2.52	0.37	0.37
6/93	3.05	0.44	0.44
7/93	3.31	0.90	0.90
8/93	3.68	0.36	0.36
9/93	3.55	0.30	0.30
10/93	3.82	0.24	0.24
11/93	3.23	0.45	0.45
12/93	3.26	0.30	0.30
1/94	3.31	0.27	0.27
2/94	3.24	0.39	0.39
3/94	3.29	0.41	0.41
4/94	3.55	0.31	0.31
5/94	3.53	0.52	0.52
6/94	3.83	0.94	0.94
7/94	3.04	0.69	0.69
8/94	3.35	0.80	0.80
9/94	3.84	0.57	0.57
10/94	3.78	0.60	0.60
11/94	3.25	0.56	0.56
12/94	2.98	0.43	0.43
1/95	3.40	0.06	0.18
2/95	3.79	0.49	0.81
3/95	3.64	0.24	0.69
4/95	3.18	0.94	0.53
5/95	3.90	0.79	0.47
6/95	3.89	0.69	0.31
7/95	4.17	0.86	0.80
8/95	3.38	0.55	0.59
9/95	3.32	0.44	0.44
10/95	3.08	0.37	0.76
11/95	3.41	0.47	0.53
12/95	3.32	0.61	0.31
1/96	3.73	0.58	0.43
2/96	3.93	0.38	0.41
3/96	3.80	0.35	0.39
4/96	4.10	1.15	0.59
5/96	3.62	0.93	0.47
6/96	3.76	0.96	0.46
7/96	3.50	0.63	0.63
8/96	2.94	0.44	0.40
9/96	3.62	0.87	0.56
10/96	3.76	0.57	0.28
11/96	3.65	0.49	0.22
12/96			

1. Standard deviation of monthly average.

FIGURE 5.8.1-1  
 NO<sub>x</sub> EMISSIONS – UNIT 1  
 1992-1996



# NOx Emissions -- Unit 2 1992-1996

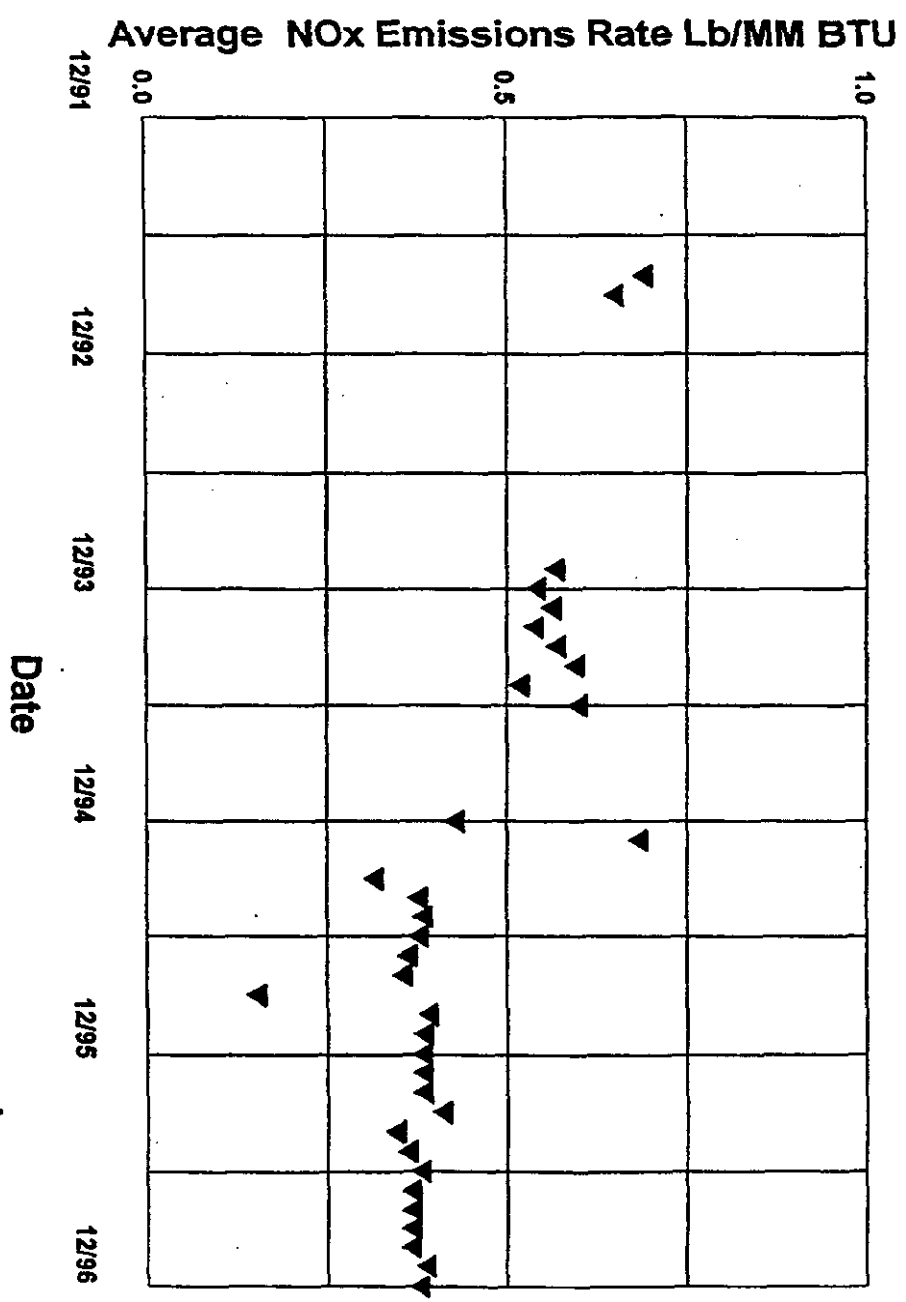
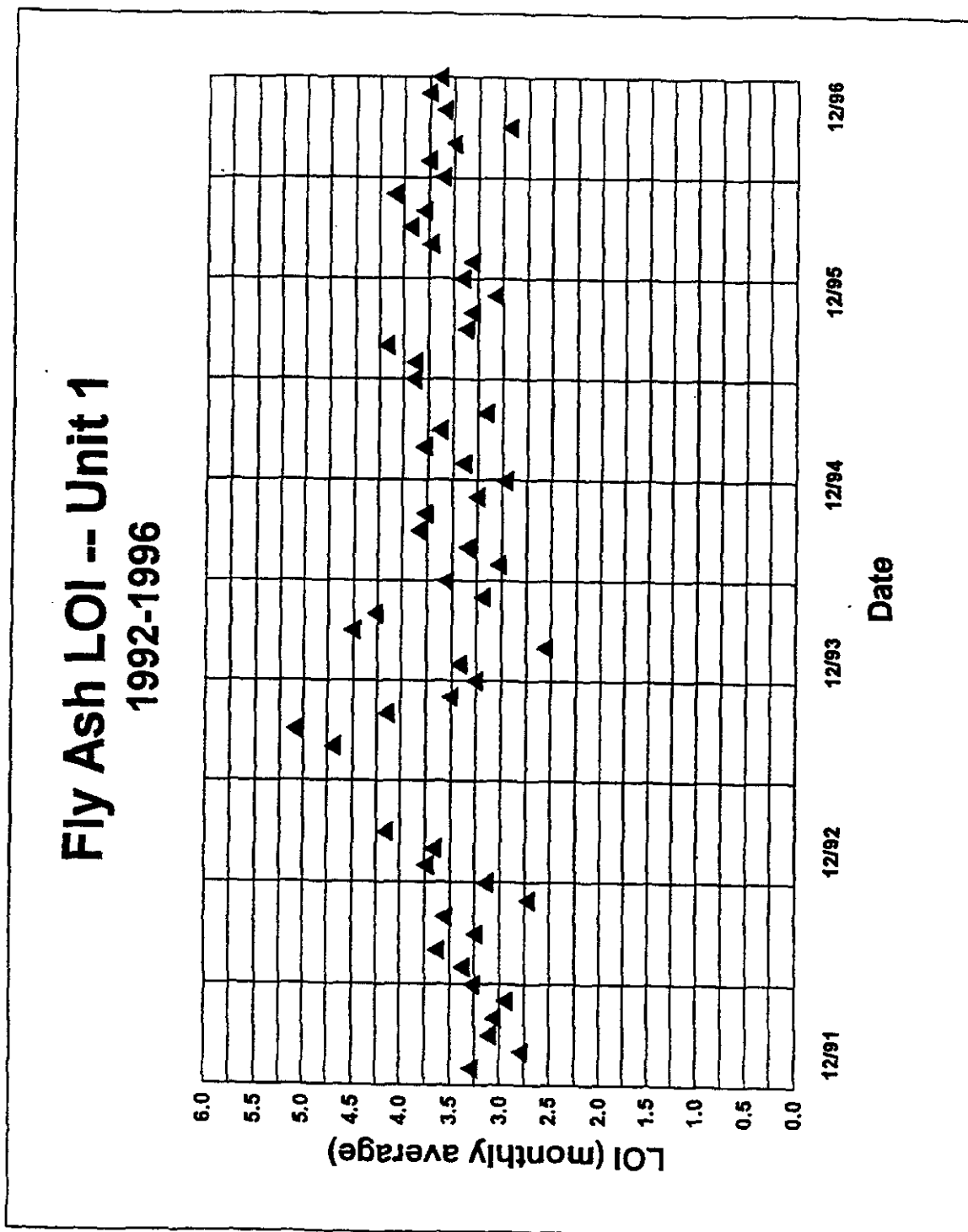


FIGURE 5.8.1-2  
NO<sub>x</sub> EMISSIONS - UNIT 2  
1992-1996

FIGURE 5.8.1-3  
FLY ASH LOI - UNIT 1  
1992-1996



# FLY ASH LOI -- Unit 2 1992-1996

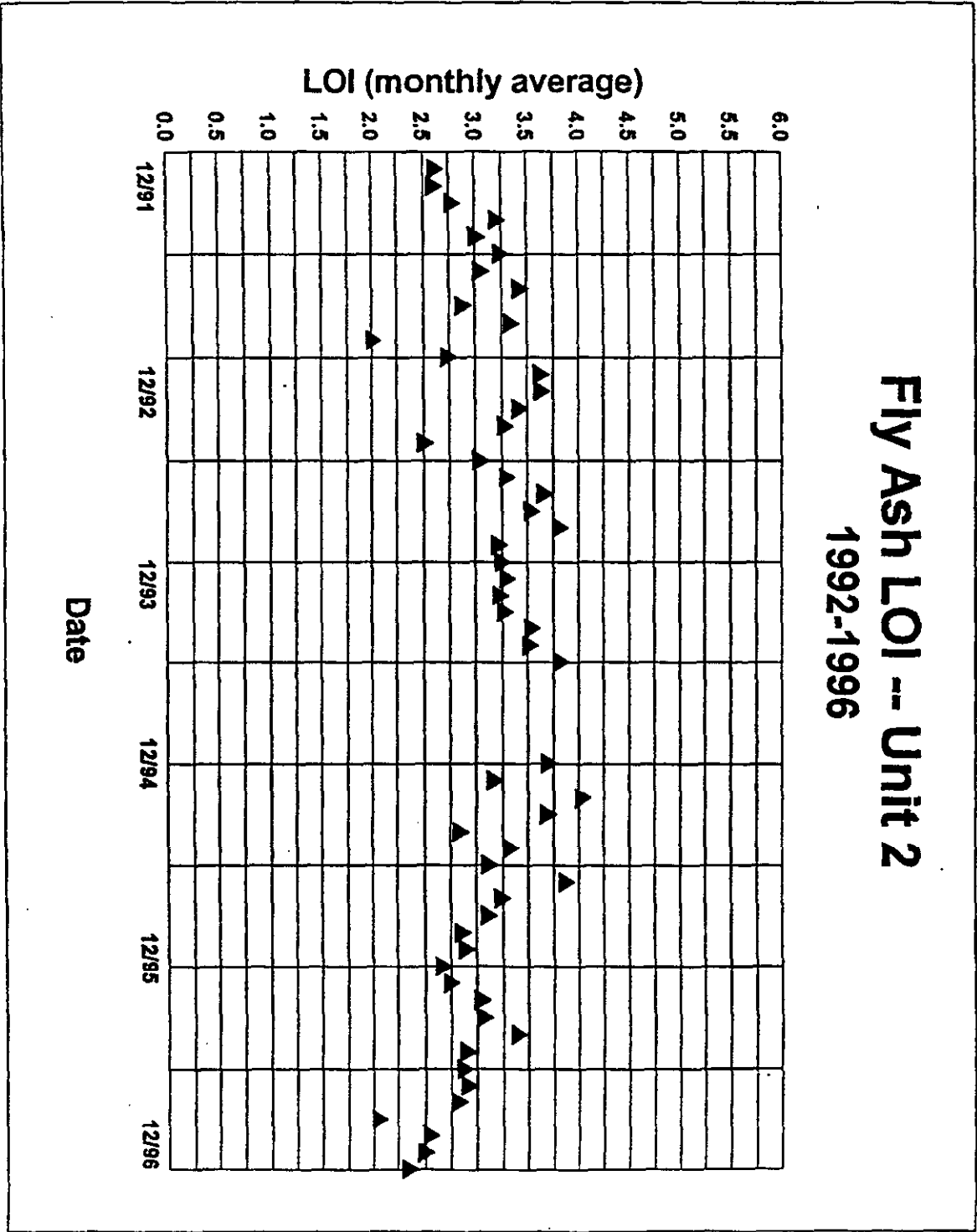


FIGURE 5.8.1-4  
FLY ASH LOI - UNIT 2  
1992-1996



# **APPENDIX A TO IMPACT OF LOW-NO<sub>x</sub> BURNERS ON UTILIZATION OF FLY ASH EVALUATION OF FLY ASH FROM THE NYSEG MILLIKEN STATION FOR USE IN CONCRETE**

## **SUMMARY**

The quality of two fly ash samples collected from Unit 2 of the NYSEG Milliken Station before and after installation of the low NO<sub>x</sub> burners was determined according to the ASTM C618 protocols. The objective was to determine the impact of the low NO<sub>x</sub> burners on the marketability of the fly ash for use as an admixture in Portland cement concrete. Both fly ash samples meet all ASTM C618 specifications for use as a mineral admixture in Portland cement concrete. Except for particle size, there was no substantial difference in the chemical compositions or the physical properties of the two fly ashes. The finer particle size in the fly ash collected after installation of the low NO<sub>x</sub> burners may be related to the new coal mills at Milliken Station. The loss-on-ignition (LOI) of the fly ash increased only slightly from 2.9% to 3.4% after installation of the low NO<sub>x</sub> burners, yet it remained well within the ASTM specification of 6% maximum.

## **INTRODUCTION**

Low NO<sub>x</sub> burners are the technology of choice to meet the Title IV utility NO<sub>x</sub> emissions limits under the Clean Air Act Amendments of 1990. However, conversion to low NO<sub>x</sub> burners results in changes in fly ash quality, such as an increase in fly ash LOI. High LOI can adversely affect fly ash properties and disqualify fly ash for use in concrete. Fly ash from Milliken Station is marketed by Pozzolanic International for use as partial replacement of Portland cement in concrete. Therefore, the potential impact of the new low NO<sub>x</sub> burners at Milliken Station on fly ash quality is of concern.

To set benchmarks for ash quality at Milliken Station, two samples of fly ash were taken at Unit 2 before and after installation of the low NO<sub>x</sub> burners (LNCFS-3). The plant was burning CONSOL Bailey Mine coal when both samples were taken. The quality of the two fly ash samples was determined according to the ASTM C618 protocols.

## **EXPERIMENTAL**

Two fly ash samples were collected from Unit 2 of the NYSEG Milliken Station before (November 19-20, 1993) and after (October 17-18, 1995) installation of the low NO<sub>x</sub> burners in December 1994. The samples were collected by NYSEG personnel from the pneumatic line between the ESP hoppers and the fly ash storage silo using an extraction sampler eight hrs/day for each day. The daily samples were combined and riffled for homogenization before testing. The fly ash evaluation tests were conducted in accordance with the procedures cited in ASTM C3 II and the results were evaluated by comparison with specifications listed in ASTM C618. ASTM C618 specifies the requirements of fly ash for use as a mineral admixture in Portland cement concrete.

## RESULTS AND DISCUSSION

Both chemical and physical properties were determined for the two fly ash samples and compared with the ASTM C618 specifications. Test results obtained for the two fly ashes and the ASTM C618 specifications are listed in table 5.8.1-A1. The results are discussed below.

### Chemical Composition

As shown in table 5.8.1-A1, the chemical compositions of the fly ashes collected before and after installation of the low NO<sub>x</sub> burners are within the requirements of ASTM C618 for use as a mineral admixture in Portland cement concrete. The two fly ashes have similar SiO<sub>2</sub>, Al<sub>2</sub>O<sub>3</sub>, and Fe<sub>2</sub>O<sub>3</sub> contents. The total amounts of these three components (88.65% and 87.57%, respectively) are well above the minimum limit of 70% for Class F fly ash. The two fly ashes also have similar SO<sub>3</sub> contents (0.83% and 0.93%) and moisture contents (0.19% and 0.16%), which are well below the maximum limits (5.0% SO<sub>3</sub> content max, and 3.0% moisture content max), as required by ASTM C618. The loss on ignition (LOI) of the fly ash collected after installation of the low NO<sub>x</sub> burners is slightly higher than the base-case sample, 2.87% vs. 3.38%, but both are well within the requirements of ASTM C618 (6.0% max). The two fly ashes have essentially the same available alkali contents (0.51% and 0.52%, reported as soluble Na<sub>2</sub>O), which are well below the maximum limit (1.50%).

### Physical Properties

As shown in Table 5.8.1-A1, the physical properties of the fly ashes collected before and after installation of the low NO<sub>x</sub> burners fall within the requirements of ASTM C618 for use as a mineral admixture in Portland cement concrete. The fineness of both fly ashes (12.15% and 8.51% +325 mesh) are well within the maximum limit (34% +325 mesh). The finer particle size (8.51% +325 mesh) of the later fly ash may be related to the new coal mills installed with the low NO<sub>x</sub> burners at Milliken Station in December 1994.

Mortar samples were prepared with partial replacement of the Portland cement (35% by vol.) by fly ash to determine the strength activity indices of the fly ashes. Both fly ash samples gave high strength activity indices with cement. After 28 days curing, the fly ash samples gave strength activity ratios of 116% and 122%, both well above the minimum ASTM C618 requirement of 75%. Both fly ash samples have high Pozzolanic activity indices with lime after seven days curing (929 psi and 893 psi), well above the minimum limit of 800 psi.

Both fly ashes have water requirements (93.1% and 91.3% relative to the control) which are below the maximum ASTM C618 requirement (105% of the control). Both fly ashes have autoclave expansion (soundness) of -0.051%, indicating slight contraction after autoclave treatment. This value is well below the maximum limit of 0.8% expansion. The two fly ashes have slightly higher drying shrinkage of 0.008% and 0.005% after 28 days curing than the control specimens prepared with Portland cement only. However, this is

well below the maximum limit of 0.03%. The two fly ashes have specific gravities of 2.37 and 2.39.

**TABLE 5.8.1-A1  
COMPARISON OF MILLIKEN FLY ASH PROPERTIES  
WITH ASTM C618 SPECIFICATIONS**

Parameters	Milliken Fly Ash (a) (11/19-20/93)	Milliken Fly Ash (b) (10/17-18/95)	ASTM C618-89 Specifications
<b><u>CHEMICAL COMPOSITION, wt%</u></b>			
Silicon Dioxide, SiO <sub>2</sub>	48.43	47.52	
Aluminum Oxide, Al <sub>2</sub> O <sub>3</sub>	23.50	23.45	
Iron Oxide, Fe <sub>2</sub> O <sub>3</sub>	16.72	16.60	-
Total, SiO <sub>2</sub> + Al <sub>2</sub> O <sub>3</sub> + Fe <sub>2</sub> O <sub>3</sub>	88.65	87.57	70.0 (Min)
Sulfur Trioxide, SO <sub>3</sub>	0.83	0.93	5.0 (Max)
Moisture Content	0.19	0.16	3.0 (Max)
Loss-on-ignition (LOI)	2.87	3.38	6.0 (Max)
Sodium Oxide, Na <sub>2</sub> O	0.44	0.68	--
Potassium Oxide, K <sub>2</sub> O	1.79	1.71	--
Available Alkalies (as Na <sub>2</sub> O)	0.51	0.52	1.50 (Max)
<b><u>PHYSICAL TEST RESULTS</u></b>			
Fineness <sup>(c)</sup> , % Retained on #325 Sieve	12.15	8.51	34 (Max)
Strength Activity Index with Portland Cement, <sup>(d)</sup>			
Ratio to Control @ 28 days	116	122	75 (Min)
Pozzolanic Activity Index with Lime, (d) at 7 days, psi	929	893	800 (Min)
Water Requirement, <sup>(d)</sup> , % of Control	93.1	91.3	105 (Max)
Soundness <sup>(e)</sup> (Autoclave Expansion), %	-0.051	-0.051	0.8 (Max)
Drying Shrinkage, <sup>(f)</sup>			
Increase at 28 days, %	0.008	0.005	0.03 (Max)
Specific Gravity <sup>(g)</sup>	2.37	2.39	

(a) Sample collected before installation of low-NOx burners at NYSEG Milliken Station

(b) Sample collected after installation of low-NOx burners at NYSEG Milliken Station

(c) Determined in accordance with ASTM Methods C430 and C311

(d) Determined in accordance with ASTM Methods C109 and C311

(e) Determined in accordance with ASTM Methods C151 and C311

(f) Determined in accordance with ASTM Methods C157 and C311

(g) Determined in accordance with ASTM Methods C188 and C311

## 5.8.2 IMPACT OF AMMONIA ON FLYASH MARKETABILITY

Flyash, which is marketed as concrete additive, can be adversely affected by the installation of the Low NO<sub>x</sub> Concentric Firing System (LNCF) and the Selective Non-Catalytic Reduction (SNCR) process. Increased carbon and ammonia concentrations can result in unmarketable ash. One objective of the By-Product Utilization Study was to analyze flyash both pre- and post-LNCF/SNCR installation to determine impacts on the sale of ash due to changes in ash composition. Two reports were planned addressing different aspects of flyash marketability. One report was to evaluate the effects of LNCF operation on flyash loss-on-ignition (LOI). Another was to evaluate effects of various ammonia concentrations on the marketability of flyash. The report of the impact of ammonia on flyash was to be based on data generated by the NOXOUT@SNCR demonstration at Seward Station. Problems with the demonstration program at Seward precluded completion of this portion of the study.

## 5.8.3 CALCIUM CHLORIDE MARKET OPPORTUNITIES

The following is a summary of the report entitled "Calcium Chloride Marketing Opportunities: a Flue Gas Desulfurization Waste Stream Alternative." The report was authored by CONSOL, Inc. Copies are available from DOE upon request. The purpose of the report is to help utility decision makers assess the CaCl<sub>2</sub> industry in North America, with a view towards identifying potential market opportunities for selling CaCl<sub>2</sub>, which can be produced by upgrading FGD waste streams. The report begins with a section on the sources of CaCl<sub>2</sub> and production methods worldwide. It then describes in detail the major worldwide uses for CaCl<sub>2</sub>. Next, the report gives the various product forms and specifications. The final section contains details on CaCl<sub>2</sub> consumption and pricing in North America. A copy of the full report can be obtained from DOE.

In 1992, U.S. CaCl<sub>2</sub> production capacity was estimated to be 848,000 short tons (100% basis), with an additional 360,000 short tons of capacity in Canada and Mexico (where production facilities are located near U.S. borders). During the same period of time industry sources estimated the U.S. demand to be approximately 590,000 short tons. From all available information, capacity has always exceeded demand. In addition to the CaCl<sub>2</sub> from Canada and Mexico, there are some minor exports from Asia (to the west coast) and from Europe. However, according to industry sources, these imports from overseas represent a very small fraction of U.S. consumption.

The principal uses for CaCl<sub>2</sub> include: de-icing (40%); dust control and road stabilization (20%); and industrial (20%). Product demand is seasonal, with peaks in the spring/summer for the dust control and soil stabilization markets, and winter for the de-icing markets. These markets, representing at least 60% of the total demand, are weather dependent. Wet summers and/or dry winters have a significant impact on CaCl<sub>2</sub> consumption. The de-icing markets are concentrated in the north and northeast U.S., while the dust control and soil stabilization markets exist throughout the U.S.

Currently, CaCl<sub>2</sub> is produced at 16 facilities within North America (12 in the U.S.). Output from 9 of these facilities is controlled by four companies (Dow Chemical, Tetra Chemical,

General Chemical, and Hill Brothers), representing approximately 90% of the total industry capacity in North America.

Calcium chloride is a naturally occurring and synthetically produced chemical. The majority of  $\text{CaCl}_2$  in North America is recovered from natural brines and salt deposits (54% of estimated current production capacity). The two other sources of  $\text{CaCl}_2$ , both synthetic, are a by-product of the Solvay process (29%), and from the neutralization of hydrochloric acid (17%). The only sources of  $\text{CaCl}_2$  produced in the U.S. are via recovery from brines and from the neutralization of hydrochloric acid.  $\text{CaCl}_2$  production in Canada and Mexico is a by-product from the Solvay process with a small fraction in Canada recovered from brines. Based on production capacity, Michigan ranks as the largest potential producer of  $\text{CaCl}_2$  in North America (47%), followed by Ontario (28%), and Louisiana (14%).

Calcium chloride is produced for sale as a liquid brine (30%-45%, but most commonly as 32%-38%), and as a solid, ranging from 77%-80% (which corresponds to the natural dehydrate) to greater than 90% dry. The brine is used in both de-icing applications as well as direct application to road surfaces to control dust. As a de-icing agent,  $\text{CaCl}_2$  is more effective at lower temperatures than the more commonly used rock salt. However, it is more expensive and more corrosive than rock salt, and thus, represents only a fraction of the total snow/ice removal markets. Frequently, the  $\text{CaCl}_2$  brine is mixed with rock salt and applied directly to the road surface. This combined mixture accelerates melting of snow and ice.

Solid  $\text{CaCl}_2$  is available as a powder, or as flakes or pellets and sold for de-icing, oil and gas well drilling fluids, concrete additive, and other markets. While the end-use form of  $\text{CaCl}_2$  for these markets is often a brine, some of the  $\text{CaCl}_2$  sold to these markets is as a solid in order to reduce transportation expenses.

$\text{CaCl}_2$  is marketed by both product manufacturers and a nationwide network of distributors. Distributors market for several manufacturers, and provide a variety of products in addition to  $\text{CaCl}_2$ . The product manufacturers have established direct relationships with their largest customers (typically state highway departments and/or major metropolitan areas), who may purchase several thousand tons per year. However, as the majority of users may purchase less than 100 tons per year, the manufacturers more commonly rely on the network of distributors to market their product. Industry sources estimate that at least 75% of the  $\text{CaCl}_2$  sold is marketed through this network of distributors.

$\text{CaCl}_2$  is a commodity chemical, marketed to end-users principally on price and service (evaluated as the ability of the distributors to deliver product on an as-needed basis). Because of the high transportation costs associated with shipment of  $\text{CaCl}_2$  brine, and the limited capacity to produce  $\text{CaCl}_2$  in an anhydrous form, individual markets are most commonly served by nearby production facilities. For example, Tetra Chemicals, with production in Louisiana and Kansas, focuses its market in the southern U.S., while Hill Brothers' market, with production in Utah and California, is concentrated in the western

U.S. Dow Chemical and General Chemical compete in the north and northeast U.S. There are exceptions; however, the generalization is still valid.

Collectively, the above information suggests potential niche markets and pricing strategies for utilities that may be producing  $\text{CaCl}_2$  to identify and pursue these markets. The most likely customers for the quantities of  $\text{CaCl}_2$  which may be recovered by utilities from FGD waste streams (estimated in the range of 1,000 tons/year on a 100% dry basis) are regional distributors of  $\text{CaCl}_2$  and/or individual consumers of large quantities of  $\text{CaCl}_2$ . The distributors can be readily identified from classified directories. As a starting point to identify large individual customers, the purchasing or maintenance department of state, county, or local departments of transportation or highway departments should be contacted.

The typical form of  $\text{CaCl}_2$  used by highway departments is a liquid, which can be prohibitively expensive to transport. Producers that are located closer to the end-user may offer a cost advantage. Given the unique situation of utilities, the value of by-product  $\text{CaCl}_2$  ranges from a negative cost (equivalent to the cost of disposal) to a positive cost (which could be as high as current market prices).

The report draws the following conclusions:

- There are some limited (but not guaranteed) niche opportunities for utilities to sell byproduct  $\text{CaCl}_2$  in the United States (as opposed to incurring the cost of disposal).
- At a minimum, utilities should plan to produce  $\text{CaCl}_2$  brines which are at least 32%  $\text{CaCl}_2$  by weight. The selling price established by the utilities will range from \$0 (with the value of avoiding disposal costs) to the existing market price. Additional details are provided in Section 6 of the report.
- $\text{CaCl}_2$  is produced at 16 facilities within North America. Output from 9 of these facilities is purchased/marketed by four companies (Dow Chemical, Tetra Chemical, General Chemical, and Hill Brothers), representing approximately 90% of the total industry capacity in North America. Conservatively, U.S. production capacity exceeds demand by approximately 40%.
- $\text{CaCl}_2$  is an undifferentiated commodity chemical with well-established, mature markets. The principal uses/markets for  $\text{CaCl}_2$  in North America include: roadway maintenance (dust control and de-icing), 60%; industrial (coal thawing, refrigerant, wastewater treatment), 20%; oil and gas well drilling, 5%; concrete "setting" accelerant, 5%; tire ballast, 3%; and miscellaneous (de-inking, food, desiccant, etc.), 7%. Historical and projected growth of these markets is less than 2% through 1997.
- $\text{CaCl}_2$  is also produced in Europe and Asia for similar uses/markets as those in the United States and North America.

- Much of the  $\text{CaCl}_2$  sold is in the form of 32%-38% brine, which is prohibitively expensive to transport over extended distances. Thus, while excess  $\text{CaCl}_2$  production capacity does exist, utilities can capitalize on niche market opportunities if they produce by-product  $\text{CaCl}_2$  in an area close to the market and/or centralized distribution point, and at a delivered price competitive with current suppliers.
- In this case, suppliers are defined to include both the manufacturers of  $\text{CaCl}_2$ , as well as the network of distributors (which is the way that most  $\text{CaCl}_2$  is sold).
- If a utility is considering installing an FGD process and associated equipment to generate by-product  $\text{CaCl}_2$  it should identify and contact the major manufacturer(s) and distributors serving that area. Cost and ability to deliver the product on an acceptable schedule are critical to marketability. Intermediate storage of byproduct may be required in order to serve the identified market.

#### **5.8.4 THE GYPSUM INDUSTRY AND FGD GYPSUM UTILIZATION**

As utilities search for the most economical approach for implementing the Clean Air Act provisions, waste disposal costs will play a big role in their decision. It quickly becomes apparent to the utility that a solution producing usable by-products can provide potential opportunities which should be considered. Although there is considerable R&D work being done to make beneficial use of solid desulfurization wastes, currently, there is only one material which qualifies as a product with a large existing market. That material is gypsum.

Gypsum is a naturally occurring mineral which has a current demand in the United States of 26 million short tons per year. Included in this demand is a chemical (by-product) gypsum market of about 0.75 million short tons per year in the United States. About half of the chemical gypsum is produced in FGD units. Gypsum is not the only solution for utilities' disposal problems, but it is one of the most practical under current conditions.

NYSEG, along with R.A.K Associates, ORTECH and CONSOL developed a comprehensive document detailing the technical and economic aspects of the gypsum industry. Published by EPRI (EPRI TR-102652, Dated February 1994) and entitled "The Gypsum Industry and Flue Gas Desulfurization (FGD) Gypsum Utilization: A Utility Guide", the purpose of this report is to provide power utilities with a technical and economic perspective of the gypsum industry in North America, with a view to the factors affecting the utilization of flue gas desulfurization (FGD) gypsum in traditional applications. A literature search including discussions with consultants was completed on all phases of the North American gypsum industry from production through marketing. European and Asian experiences and markets are also discussed.

#### **SOURCES AND USES OF GYPSUM**

In the United States in 1992, crude gypsum production was estimated at 16.0 million short tons, while that of Canada was 9.0 million short tons. Of this total, only 0.1 million short tons were exported. Approximately 9.0 million short tons of crude gypsum were

setting properties, as inter-ground with the impurities within the /psum is the major associated corrosion in used in cement are illboard manufacture.



Handling of the finer-sized FGD gypsum may be an issue as cement plants are designed for using gypsum as a coarsely crushed rock which is added directly to the clinker for grinding.

Utilization of FGD gypsum in Portland cement manufacture has good potential. The major differences between natural and FGD gypsum are particle size/shape and moisture content as related to materials handling. In some cases, it may be necessary to dry and/or agglomerate the gypsum in order to provide a material that is more compatible with existing equipment. Chlorides are not as much of a concern since washing techniques can effectively reduce these below levels of concern. Another difference is the absence of insoluble anhydrite (anhydrous calcium sulfate) which can occur in natural deposits of gypsum. If the cement plant is accustomed to using a gypsum/anhydrite blend to control the setting of cement, some developmental work may be required prior to substituting FGD for natural gypsum. Several cases of the successful use of FGD gypsum in the manufacture of cement in the United States are known.

Cement companies usually buy gypsum on the open market from the wallboard companies, with the market value being as high as \$50 per short ton (f.o.b. cement plant). As with board manufacture, transportation is a significant component of this cost. Therefore, the economic feasibility of FGD gypsum utilization in Portland cement will depend, to a large extent, on the proximity of the supply to the cement plant.

### **Gypsum in Agriculture**

Gypsum in agriculture is used as a supplemental source of elemental sulfur and calcium, and as a soil conditioner. The specifications for this application relate mainly to toxic impurities, specifically heavy metals content. The use of FGD gypsum in agriculture is relatively straightforward and depends mainly on transportation costs and available markets.

### **Utilization of Gypsum in Plaster**

There are two main types of plasters, designated as alpha- and beta-plaster. Alpha-plaster is a higher value material [up to \$350 per short ton (f.o.b. plant)] and is produced under different and more costly conditions than that of beta-plaster. This plaster is used for specialty applications including industrial molding, dental and medical plasters, and possibly mining mortars. Due to their higher cost, alpha-plasters are not as common as aridized beta-plasters in North American floor applications. Beta-plaster is a lower value material (ranging from \$16 to \$100 per short ton, f.o.b. plant) produced via the more conventional calcination (i.e., dry) methods. In addition to wallboard manufacture, it is used in wallplasters and as a fireproof coating.

FGD gypsum has good potential for the manufacture of plasters because of its high purity. However, the plasters market is relatively small, accounting for only about 1.1 million short tons annually.

## **FGD Gypsum as a Filler**

Natural gypsum has not seen significant application as a filler material in North America, although several grades of calcium sulfate fillers are commercially available. However, certain qualities of FGD gypsum (i.e., high purity, fineness, whiteness) may make it suitable for specific filler applications. A section on mineral fillers is included in the EPR1 report which describes the properties of fillers required for different applications. The use of gypsum as a filler in some applications is also reviewed in the report.

## **Utilization of FGD Gypsum in Europe and Asia**

Utilization of FGD gypsum in Europe is more advanced than in North America. However, the European experiences are not always applicable to North America because of differences in methods of construction and consequent differences in the products manufactured. Plasters consume a much higher proportion of gypsum in Europe and much of the European experience is in the use of plasters. However, a fair quantity of wallboard is manufactured in Europe where the boards are typically of significantly higher weight. More recently, FGD gypsum has been used in wallboard manufacture and this experience is discussed in the report.

In Asia, much of the wallboard technology and plant design has been imported from the United States or Europe. Japan has a long history of by-product gypsum use (because of a lack of good quality natural deposits), but trends indicate that the traditional sources of gypsum have been shifting over the last two decades. The use of both FGD and natural gypsum has been and is continuing to increase.

## **CONCLUSIONS**

Gypsum is not an all-encompassing solution to the waste issues created for utilities trying to comply with the Clean Air Act. However, the potential for producing such a high quality raw material as a scrubber by-product presents potential opportunities which each utility must consider in relation to its own local environment.

The technical feasibility of substituting FGD gypsum for natural gypsum in traditional applications including wallboard and cement manufacture, as an agricultural soil conditioner/supplement, and in the preparation of both building and specialty plasters, has been demonstrated. With respect to the wallboard and cement industry, the physical form (particle size distribution, moisture content) is the most significant difference relative to natural rock, and may require modifications to existing materials handling equipment. In some cases, agglomeration and/or drying of the finer FGD material may be necessary by either the utility or the end user. However, as gypsum consumers become more experienced with FGD gypsum, they can learn to handle the material with only minimal additional processing by the producer (i.e., adequate dewatering). Chemical differences can be overcome and, in some cases, may be beneficial (i.e., purity and color). Effective techniques can reduce chlorides, the impurity of most concern, to levels where they do not affect processes, products or applications.

Economically, the production of a salable FGD gypsum does not add substantial costs to the utility striving to comply with the Clean Air Act. Local environmental considerations will be a factor in determining whether the production of high quality FGD gypsum is economically viable (i.e., available disposal sites and costs). As disposal costs rise, the use of FGD gypsum will be most dependent on distance and associated transportation costs between the FGD gypsum producer and consumer, as well as localized availability of cheap, natural gypsum of acceptable quality.

Wallboard and cement manufacturers are the largest consumers of gypsum, and are therefore the most obvious target markets for FGD gypsum producers. However, it is possible that in the near future, with the increasing numbers of utilities that will be producing high quality gypsum, an oversupply may exist.

Agricultural applications have been successfully demonstrated, especially in the peanut industry. The growth potential for this market could be high if yield advantages for a variety of crops can be demonstrated. Currently, this market is geographically limited to the more southern regions of the United States. However, research is currently being conducted in other regions of the United States which could potentially expand this market.

Other potential markets include specialty plasters, fillers, alternative building products and plasters for use in mining mortars. Specialty plasters would be particularly attractive if they can be produced at a competitive cost while maintaining quality.

With the possibility of oversupply in the obvious markets, it would be advantageous to the utilities to undertake research, market and product development activities to enhance the sales potential for their material in alternative markets.

**5.9 INNOVATIVE WASTE LINERS: A CASE STUDY OF THE KINTIGH STATION**

**SOLID WASTE DISPOSAL FACILITY**

**5.9.1 INTRODUCTION**

Coal-fired electric power generating facilities throughout the United States produce over 39.1 million tons of flyash and millions of tons of other wastes such as bottom ash pulverizer mill rejects, water treatment sludges generally known as coal combustion by-products. Quantities of coal combustion by-products (CCBP) of electric generation are increasing throughout the country due to increased use of combustion emission cleaning processes to meet requirements of clean air legislation. Such cleaning processes include flue gas desulfurization (FGD), fluidized bed combustion, spray drying, and duct or furnace sorbent injection. These processes could potentially double the quantity of CCBP previously requiring disposal.

Although considered a nonhazardous waste by the Environmental Protection Agency, the task of disposing of these increasing quantities of high-volume CCBP results in greater disposal costs in waste disposal facilities that, due to regulatory factors, may be over-engineered for the material disposed. One method to reduce the disposal costs is to consider innovative disposal methods and liner systems that are cost effective and yet remain protective of human health and the environment.

NYSEG submitted to EPRI a case study of an innovative disposal method and liner system for NYSEG's Kintigh Station solid waste disposal liner installation. This case study is available in its entirety from DOE upon request. The study provided:

- A description of the Kintigh generating plant, including pollution control equipment and solid waste handling systems.
- A discussion of the Facility setting relative to the physiography, climate, hydrology and geology of the site,
- The regulatory situation at the facility,
- The design and construction of the solid waste disposal area,
- An evaluation of the performance of the solid waste disposal facility using a variety of methods to quantify the physical and chemical properties of the CCBP and
- The environmental protection realized by the facility design as determined by various investigations conducted at the site.

Some of the key elements of the report are presented below.

**FACILITY DESCRIPTION**

Kintigh Generating Station (Kintigh) is a 650 megawatt nominal, coal-fired, electric generating station owned and operated by New York State Electric & Gas Corporation

(NYSEG). The station is located in Niagara County, New York on the southern shore of Lake Ontario approximately 30 miles northeast of Buffalo. Construction commenced in 1980 with the plant's commercial start-up in 1984.

Kintigh is equipped with electrostatic precipitators and a wet limestone flue gas desulfurization (FGD) system. The byproducts from these emission control devices consist of fly ash and FGD scrubber sludge. The fly ash is collected in hoppers at the bottom of the precipitators. The fly ash is then conveyed pneumatically to a silo next to the sludge stabilization building located east of the main plant.

The flue gas desulfurization system consists of six absorber modules, four required for operation, one spare and one for maintenance. A slurry of pulverized limestone and water is sprayed into the path of the flue gas, resulting in a reaction between the sulfur in the flue gas and the calcium in the limestone. The overflow from the thickener is used as make up water while the solids collected at the bottom are piped to the sludge stabilization building. At the sludge stabilization area, the FGD sludge (calcium sulfite) is further dewatered by vacuum filtering and is then blended with the fly ash and quick lime in a pug mill for stabilization. The fly ash to FGD sludge ratio depends on the ash and sulfur content of the coal being burned. Generally, the stabilized sludge fly ash to sludge ratio ranges from 0.5:1.0 to 1.0:1.0 and contains approximately 2.5% lime on a dry weight basis. The stabilized sludge is then stacked out on an asphalt pad where it is loaded and transported to the landfill via articulated dump trucks.

Another solid waste generated at the plant is pulverizer mill rejects which consist mainly of iron pyrite and other hard minerals and rock not readily crushed in the coal pulverizers. Pyrites are collected and trucked to the sludge stabilization pad where it is mixed with stabilized sludge.

Bottom ash is collected in the bottom of the boiler and sluiced with water to dewatering bins. The water is recirculated and the dewatered bottom ash is transported to the landfill where it is stockpiled. The stockpiled bottom ash is sold as traction agent on roadways during winter months or is used for landfill construction or temporary cover, as needed.

Wastewater treatment sludges, collected during the treatment of maintenance cleaning wastes and coal pile runoff are dewatered in belt presses to more than 20% solids. In addition, periodic cleaning of onsite basins results in the generation of solids which are spread and dried in the lined coal pile area until the moisture is reduced to 20% moisture or less. The dried basin sludge is then trucked to the landfill and blended with stabilized sludge for disposal.

With the exception of the stabilized sludge (flyash, FGD sludge and lime), the other solid wastes generated at the plant usually account for less than 1% of the wastes disposed at the landfill.

## FACILITY SETTING

Kintigh Station is located on the south shore of Lake Ontario in the Erie-Ontario Lowland physiographic province of New York State. The plant location has a humid, continental type of climate. Annual precipitation averages 32.6 inches per year with significant local variations. The average snowfall is 56 inches per season with lake-effect storms occurring primarily in November and December before the lake water cools. The average daily temperature ranges from 38 °F to 57 °F throughout the year. The Kintigh site has been reworked by glacial action. The geological sequence of the area consists of two units: the unconsolidated, glacial and glacio-lacustrine deposits and the underlying, Paleozoic age sedimentary rock.

Precipitation falling on the site is directed to Lake Ontario primarily by Fish Creek and an unnamed stream. Surface water quality has been assigned by the New York State Department of Environmental Conservation (NYSDEC) to Fish Creek and Lake Ontario. Fish Creek has been designated a Class C surface water which are best utilized for fishing and is suitable for fish propagation and survival. The classification also indicates that the stream is of sufficient quality for primary (swimming) and secondary contact recreation although the size of Fish Creek limit those uses. Lake Ontario is classified by the NYSDEC as a Class A water body. Class A waters are suitable as a drinking water source, used for culinary or food processing purposes, fish propagation and survival, and primary and secondary contact recreation.

Studies have established two critical ground water flow regimes at the site. The first (shallow) flow regime is located within the basal (bedrock/till interface) zone, the second is flow within the unweathered bedrock. No other continuous water bearing zones were identified within the unconsolidated deposits. Ground water monitoring wells have been installed in both flow regimes as well pairs to determine hydraulic connectivity and vertical flow directions between the flow regimes. There are large differences in hydraulic conductivities between the shallow, basal zone and the deep, bedrock zone which suggest that the two flow regimes are, generally, hydraulically separate.

Many ground water monitoring wells have been installed throughout the life of the disposal area facility. Currently there are 30 active monitoring wells where water levels are measured and water samples are collected for analysis. There are also three active piezometers where only water levels are measured. Samples have been collected and analyzed for over 13 years.

The water quality at the site is highly variable and trends are very difficult to ascertain by standard comparative review of water quality data or statistical methods. Natural background water quality indicate levels of sulfate, chloride, iron, manganese, sodium and boron above New York State drinking water standards. These analytes are usually the indicator parameters used to determine CCBP leachate impacts on the environment, thus making evaluation of potential leachate impacts on the ground water difficult using traditional statistical approaches.

Table 5.9-1 is a summary of the various constituents encountered in the ground water and leachate as compared to sea water and New York State regulatory standards and vividly illustrates the problem.

## **REGULATORY SITUATION**

At the time of plant licensing and construction, the liner requirements for proposed landfills called for "a natural or artificial liner that restricts infiltration to the equivalent of five feet of soil at hydraulic conductivity of  $1 \times 10^{-5}$  cm/sec or less..." In addition the guidelines also called for a liner with a hydraulic conductivity of  $1 \times 10^{-6}$  cm/sec or less under and over all pyrite disposal cells and under all sludge disposal areas.

Current New York State solid waste regulations require a double composite liner system (two liners consisting of a synthetic geomembrane directly overlaying 18 inches of low permeability soil with a hydraulic conductivity of less than  $1 \times 10^{-7}$  cm/sec separated by a leak detection layer) or an approved alternative design provided it is protective of the environment based on the wastes to be disposed of in the landfill. These regulations are primarily directed at municipal sanitary landfills throughout the state but do allow site and/or waste specific modifications if the changes meet New York State Department of Environmental Conservation (NYSDEC) approval.

### **5.9.2 DESIGN AND CONSTRUCTION OF SOLID WASTE DISPOSAL AREA (SWDA)**

The initial solid waste disposal design called for utilizing flue gas desulfurization (FGD) sludge stabilized with fly ash as a full depth liner for ground water protection from the CCBP produced at the plant. It was NYSEG's intention to dispose of coal combustion and other plant wastes in a manner that would take full advantage of the excellent structural and environmental properties of the stabilized sludge material. NYSEG elected to use the stabilized material as a monolithic liner which eliminates the need for an underdrain and leachate collection system. The design and disposal scheme employs a proven pozzolanic fixation process which utilizes flyash and lime to produce a cementitious, low permeability and structurally stable material. The FGD sludge, which is difficult to landfill due to its unstable nature, is mixed with the flyash and lime to provide a structurally sound material. This material which is referred to as stabilized sludge is capable of permeabilities of  $1 \times 10^{-6}$  cm/sec.

**TABLE 5.9-1  
SUMMARY OF SELECTED WATER CHEMICAL CONSTITUENTS AT KINTIGH SWDA**

Parameter	Sampling Location						NY Class GA Standards
	Queenston Shale <sup>1</sup>	Salt Spring <sup>2</sup>	Upgradient Well 9128D <sup>3</sup>	Leachate <sup>4</sup>	Seawater <sup>5</sup>		
Bicarbonate	9-372	62.5-104	36.6-58.3	35.6-63.1	144	NA	
Chloride	90-3,150	35,900-41,400	7,440-10,800	6,650-10,800	19,300	250	
Hardness	219-1,910	22,900	3,610	6,010-8,960	1,698	NA	
Total Dissolved Solids	533-8,920	61,300-63,600	13,400-19,300	12,800-20,500	35,000	500	
Sulfate	-	877-965	642-1,120	462-1,050	2,688	250	
Sodium	-	13,800-16,100	3,270-4,930	1,240-1,800	10,714	20	
Conductivity (mmhos)	927-11,900	76,400-89,400	18,650-31,700	18,150-29,800	-	NA	

NOTES: All results in mg/l unless noted  
NA = Not Applicable

REFERENCES:

- 1) From Johnston, 1964 - 10 analyses except Conductivity (8)
- 2) NYSEG data from 1992 - 3 analyses except Hardness (1)
- 3) NYSEG data from 1994 - 4 analyses except Hardness (1)
- 4) NYSEG data from 1994 - 12 analyses except Hardness (3)
- 5) From Krumbien and Sloss, 1963



## **INITIAL DESIGN PROGRAM**

A testing program was established to demonstrate the suitability of using stabilized sludge as a monolithic liner. Physical, chemical and engineering properties of stabilized sludge were evaluated across a range of fly ash, lime and FGD sludge ratios.

The fly ash used for this initial evaluation was obtained from NYSEG's Milliken Station, since the coal was similar to the design coal for Kintigh Station. Results of the bulk chemical analysis conducted on the fly ash sample are displayed in table 5.9-2. The primary constituents of fly ash include silica, alumina, and iron in concentrations typical of most pulverized coal ash.

The FGD sludge used for the stabilized sludge evaluation was obtained from Indianapolis Power and Light's (IPL) Petersburg Station. The Petersburg Station utilized a wet, limestone-based FGD scrubber similar to the system proposed for Kintigh Station. Results of the bulk chemical analysis of the FGD sludge are also presented in table 5.9-2. The primary constituents of the FGD sludge include calcium sulfate, calcium sulfite, and calcium carbonate, which are typical of wet limestone FGD scrubbers.

The stabilization of FGD sludge with fly ash and lime is an application of a pozzolanic fixation process that is used extensively within the solid waste industry. FGD sludge is processed to achieve a sludge of high enough solids content to be combined with fly ash and lime and subsequently landfilled.

The mixture of lime and fly ash undergoes a pozzolanic reaction producing cementitious compounds which bind individual particles together. This reaction is time dependent which slowly increases the mixture's strength over time. The FGD sludge is not a part of the pozzolanic reaction and is entrained with the interstices of the cementitious compounds and appears to aid in reduced permeabilities. The addition of lime to the mixture also improves leachate quality with constituents chemically combined into less soluble components. The pore water and sludge solids are also physically encapsulated within the matrix of the cementitious compounds. Permeabilities and unconfined compressive strengths from the test program are displayed in table 5.9-3 and typically are less than  $1.0 \times 10^{-6}$  cm/sec and greater than 50 psi, respectively. As illustrated by the table, curing time and mixture ratios can have a large effect on these values.

The stabilized material possesses properties that allow construction of monolithic above-ground structural fills, limited in height only by the bearing strength of the underlying soil foundation and the external slopes requiring vegetation for runoff control. The low permeability of the monolith virtually eliminates the need for leachate collection systems which reduces construction costs.

Test mixtures were cured for 28, 60 and 90 days at 73 °F and 95% humidity to simulate conditions within the landfill. The curing periods were selected to provide data on the

during normal operations. 4.0:1.0. These outside ratios were considered to be extreme conditions unlikely to occur. The initial design program used fly ash to FGD sludge mix ratios ranging from 0.44:1.0 to 2.5:1.0. The actual ratio for 1995 varied from 0.44:1.0 to 1.5:1.0. Variations in coal properties such as ash and sulfur content affect the actual quantities of waste generated. The ratio of fly ash to sludge on a dry weight basis using the design average coal is 1.14:1.0. The actual ratio for 1995 varied from 0.44:1.0 to 1.5:1.0. Variations in coal based on a coal with an ash content of 12% and sulfur content of 2.5%, at 1 00% load characteristics of coal burned. The initial solid waste disposal design quantities were The quantity of fly ash and FGD sludge produced at Kintigh Station varies with the

N/A - Not Analyzed

Ratio of Fly Ash to FGD Sludge (dry weight)	Hydraulic Conductivities (cm/sec)	Unconfined Compressive Strength (psi)
28 day cure	60 day cure	90 day cure
0.44/1.0	1.7 x 10 <sup>-5</sup>	0.5 x 10 <sup>5</sup>
0.66/1.0	2.0 x 10 <sup>-5</sup>	0.8 x 10 <sup>5</sup>
1.0/1.0	1.2 x 10 <sup>-5</sup>	0.5 x 10 <sup>5</sup>
1.14/1.0	0.5 x 10 <sup>-5</sup>	N/A
1.5/1.0	1.3 x 10 <sup>-5</sup>	1.0 x 10 <sup>5</sup>
2.0/1.0	1.9 x 10 <sup>-5</sup>	1.0 x 10 <sup>5</sup>
2.5/1.0	0.6 x 10 <sup>-5</sup>	0.9 x 10 <sup>5</sup>
3.0/1.0	0.6 x 10 <sup>-5</sup>	0.1 x 10 <sup>5</sup>
4.0/1.0	1.5 x 10 <sup>-5</sup>	0.6 x 10 <sup>5</sup>

**TABLE 5.9-3**  
**HYDRAULIC CONDUCTIVITIES AND COMPRESSIVE STRENGTHS OF STABILIZED SLUDGE TEST MIXTURES USED DURING INITIAL DESIGN EVALUATION**

Parameter	Milliken Station Fly Ash (ppm)	IPL - Petersburg Station FGD Sludge (ppm)
Silica	510,000	2,100
Alumina	15,000	N/A
Iron	98,000	N/A
Calcium	4,800	343,000
Magnesium	50	N/A
Sodium	950	N/A
Sulfite	<10	128
Sulfate	N/A	460,000
Acid Insolubles	952,000	116,100
Loss on Ignition	2,000	7,000

**TABLE 5.9-2**  
**FLY ASH AND FGD SLUDGE ANALYSES USED DURING INITIAL DESIGN EVALUATION**

time dependency of the pozzolanic reactions. The temperature selected was considered to be conservative, with the actual temperature within the fill likely to exceed 80 °F due to the exothermic pozzolanic reaction. Temperatures on the outer edges of the fill may be lower than 40 °F during winter months which retards the reaction, however, as successive lifts are placed, the insulation provided by the additional material will decrease the reaction time.

The initial handling characteristics of the stabilized sludge are dependent on the fly ash and FGD sludge mixture ratio, which is dependent on the coal characteristics. Preferred moisture content is the minimum which will facilitate loading, hauling and placement in the landfill. Due to the cementitious nature of the stabilized sludge, the actual dry density of the stabilized sludge placed in the landfill is not critical, beyond what is achievable with normal construction equipment.

As the fly ash to FGD sludge ratio increases, moisture content will decrease to a point where the optimal moisture content will be reached. This occurs at a ratio of approximately 2.5:1.0. At this ratio, the natural moisture content of the stabilized sludge will allow achievement of optimum density. Ratios greater than this will require addition of moisture to achieve optimum density. Moisture addition at Kintigh Station, if required, occurs at the sludge stabilization area where the fly ash, FGD sludge and lime are mixed.

At ratios less than 2.5:1.0, handling characteristics change as fly ash content is reduced. Ratios greater than 1.0:1.0 allow the stabilized sludge to be landfilled directly. Ratios less than 1.0:1.0 require the stabilized sludge to be stored at the sludge stabilization pad for a time to allow the pozzolanic reactions to commence thus stiffening the stabilized sludge so that it can be hauled and placed with normal construction equipment. Kintigh Station has a five day stockpiling capacity at the stabilization pad.

The engineering properties of the stabilized sludge were evaluated over the range of fly ash to FGD sludge ratios. The key property in the evaluation of structural stability is the unconfined compressive strength (UCS), which in a cemented material is equivalent to two times the apparent cohesion or cohesive strength of the material. Use of the UCS is a conservative approach which neglects the internal friction angle which contributes to the in-place shear strength of the material. A UCS of 25 psi is equivalent to a cohesion value of 12.5 psi (1800 pounds per square foot). The incorporation of this cohesion value in a slope stability analysis for the Kintigh facility resulted in a safety factor of greater than 2.0 which is considered an acceptable factor of safety against failure.

The final in-place properties of the stabilized sludge are similar to that of a weak cement or soft rock. The exposed surface which is subject to weathering during wet/dry and freeze/thaw cycles can result in a breakdown of the outer surface of the material. This breakdown can progress several inches into the outer surface of the stabilized sludge. Intermediate or final soil covers are effective in eliminating this effect.

The range of Unconfined Compressive Strengths (UCS) measured over the design range of fly ash and FGD sludge mixture ratios are presented in table 5.9-3. The initial tests of UCS ranged from 52 psi to 555 psi over the range of mix ratios. As anticipated, the

higher the fly ash content, the higher the UCS developed. These mixtures were made using 3.0% quicklime (CaO) addition on a dry weight basis. These results indicate lower amounts of lime may be added to the mixture and still maintain a UCS that exceeds the safety factor required. Strength increases over time due to the pozzolanic reactions. Values of UCS (28 day cure) that were actually achieved at Kintigh from 1991 to 1996 are provided in table 5.9-4.

To determine the suitability of stabilized sludge as a full thickness liner, the coefficient of permeability was determined in the laboratory over the range of test mixtures. These results are presented in table 5.9-3. As anticipated, the stabilized sludge became more impermeable with increased curing time. The decrease in permeability is expected to continue at a slower rate for more than a year as the pozzolanic reaction continues. Values of permeability (90 day cure) that were actually achieved at Kintigh from 1991 to 1996 are provided in table 5.9-4.

**TABLE 5.9-4  
HYDRAULIC CONDUCTIVITIES AND COMPRESSIVE STRENGTHS OF STABILIZED  
SLUDGE PRODUCED AT KINTIGH STATION 1991 - 1996**

Year	Hydraulic Conductivity(cm/sec) 90 day cure	Unconfined Compressive Strength (psi) 28 day cure
1991	$5.62 \times 10^{-5}$ - $4.76 \times 10^{-5}$	54.6 - 168.9
1992	$5.84 \times 10^{-5}$ - $1.53 \times 10^{-5}$	104.6 - 268.7
1993	$7.25 \times 10^{-5}$ - $1.43 \times 10^{-5}$	53.2 - 287.4
1994	$4.40 \times 10^{-5}$ - $2.97 \times 10^{-5}$	31.7 - 272
1995	$9.20 \times 10^{-5}$ - $1.01 \times 10^{-5}$	12.4 - 27.1
1996	$1.00 \times 10^{-5}$ - $2.90 \times 10^{-5}$	46.0 - 90.3

Stabilized sludge samples collected from the stockout pile at the mixing facility.

1) UCS lower than reported in previous years due to laboratory procedure error.

Landfills are typically constructed with the slope method which provides positive drainage from the waste material. Therefore the standing head of water required to reach saturation of the waste material is not present. Full saturation of a material is required for flow to begin through it. The Kintigh SWDA is constructed by the slope method using multiple lifts during each phase and subphase of the landfill. Ponding or surface retention of water is eliminated through proper grading and sloping of the compacted surface. In effect, the stabilized sludge acts as a full depth inverted liner or cap sealing the natural soil subgrade. Runoff is diverted into swales and ditches which discharge into the on-site retention basins.

The ultimate bearing capacity of a soil or soil-like material such as stabilized sludge is the unit pressure at which soil rupture occurs under a footing. As soil rupture occurs, masses of soil are thrust aside as the footing breaks into the ground. Developing a value of ultimate bearing capacity requires information regarding the size and shape of the

foundation element, the depth of the foundation beneath the ground, and the nature of the material on which it rests.

Using a safety factor of 2.0, the allowable bearing capacity of stabilized sludge having a UCS ranging from 25 to 75 psi will be between 3 and 10 tons per square foot. Foundation soils were calculated to potentially settle a maximum of 16 inches under the maximum design load which was considered negligible and not a factor of concern in the landfill design.

## WASTE CHARACTERISTICS

Concentrations of constituent oxides of the as-produced stabilized sludge during 1996 are presented in table 5.9-5. Concentrations of stabilized sludge compositional metals are compared to New York State land application limits and are presented in table 5.9-5. As can be seen, all metals with a regulatory limit are well below the limits established.

**TABLE 5.9-5  
STABILIZED SLUDGE CONSTITUENT OXIDE ANALYSIS**

CONSTITUENT OXIDES (%)	1/4/96	4/13/96	7/9/96	10/21/96
Alumina	4.4	6.7	13	11
Calcium Oxide	3.0	17	39	34
Iron Oxide	3.9	3.7	9.4	8.4
Magnesium Oxide	0.79	0.8	1.6	1.1
Sodium Oxide	0.15	0.6	0.3	0.5
Silica	9.2	14	26	25
<b>OTHER CHARACTERISTICS</b>				
Sulfite (mg/kg)	350,000	4,800	13,000	140,000
Loss on Ignition (%)	3.1	1	3.9	6.0

## LEACHATE CHARACTERISTICS

Theoretical leachate characteristics can be simulated through several different tests. At the time of initial landfill design, the EPA's Extraction Procedure Toxicity Test (EP Tox) was the primary method used to determine worst-case leachate characteristics at sanitary landfills. Waste material is subjected to extraction with acetic acid and the resulting leachate analyzed. The results typically show higher concentrations of various parameters than would be expected in a landfill disposing of non-organic wastes. The EP Tox method has since been superseded by the EPA's Toxic Characteristics Leaching Protocol or TCLP.

The second method used during initial design was the ASTM 48-hour water shake method. In this test, the waste material is subject to extraction with distilled water. This method more accurately reflects conditions expected in the landfill.

The results of the two methods are presented in table 5.9-7. Analytical results from the actual limited leachate generated within the landfill are also presented for comparison in

table 5.9-8. As can be seen, toxic metal concentrations are well below the hazardous waste limits promulgated by the EPA.

At the low permeability developed and through proper landfill operation, the potential for saturation and permeation is significantly reduced. Due to the design of the landfill, however, surface water contact is unavoidable although cover material minimizes the surface water contact. The surface water is collected prior to discharge through SPDES permitted outfalls.

It is unlikely that ground water will come into contact with the waste material due to the reduction in recharge from precipitation to the water table.

Leachate production within the stabilized sludge is limited due to a combination of chemical, physical, and operational characteristics of the landfill.

Chemical species present in pozzolanic systems are rendered insoluble by several mechanisms. First, the final pH of the system ranges from 11 to 12 Standard Units. At these levels, most metals form insoluble, metal hydroxide precipitates. Second, the pozzolanic reaction is a crystallization process in which calcium-alumino silicates are formed. The crystalline material is insoluble and entrains many chemical species within the crystal matrix. Third, FGD sludges contain high concentrations of sulfate and sulfite compounds, many of which are insoluble.

The filling of voids by pozzolanic compounds reduces permeability, which in turn reduces the flow of water through the waste mass effectively limiting leachate production.

Operating the landfill to promote maximum surface water runoff also reduces leachate production. Since little or no water remains on the surface of the fill for extended periods, there is a minimal amount of water available to permeate through the stabilized material. The initial resistance to saturation and the continual removal of surface water reduces the potential for development of the driving force or hydraulic gradient necessary to initiate and maintain a flow of leachate through the stabilized mass.

**TABLE 5.9-6  
STABILIZED SLUDGE COMPOSITIONAL METALS ANALYSIS**

Collection Date	Compositional Metals (ppm)													
	Ag	As	Ba	Cd	Cr	Cu	Hg	Mn	Ni	Pb	Se	Zn		
29-Apr-91	12	15	<30	<0.5	56	NA	0.0033	130	NA	10	10	65		
23 Jul-91	25	30	200	<3	55	NA	0.44	120	NA	<50	25	75		
24-Oct-91	<25	16	150	4	75	NA	0.2	140	NA	<50	2	130		
30-Jan-92	30	1	<200	<3	<30	NA	0.54	50	NA	<50	1	340		
22-Apr-92	90	65	350	<3	140	NA	0.52	120	NA	<50	1	750		
21-Jul-92	140	38	200	<3	---	NA	0.97	100	NA	50	3	230		
15-Oct-92	<30	17	200	<3	50	NA	---	100	NA	200	0	55		
17-Mar-93	<5	41	180	<0.5	86	NA	0.5	110	NA	30	<1	80		
15-Jun-93	<5	<5	100	0.7	45	NA	<0.4	70	NA	20	12	50		
15-Sep-93	<5	50	130	1.8	79	NA	---	91	NA	<10	<2	68		
27-Dec-93	<5	45	89	1.8	65	NA	---	96	NA	<10	3.4	110		
Regulatory Limit	---	---	---	25	1000	1000	10	---	200	1000	---	2500		

--- Data unavailable

NA Not analyzed

(1) Regulatory limits established for land application of sewage sludge and septage in Subsection 6 NYCRR 360-4.4(a).

**TABLE 5.9-7  
STABILIZED SLUDGE LEACHATE ANALYSES FOR RCRA TOXIC METALS**

Parameter	EP Tox Limits(mg/l)	EP Tox <sup>1</sup> (mg/l)	EP Tox Range 1/90 - 7/92 (mg/l)	TCLP Limits(mg/l)	TCLP Range 10/91 - 10/95 (mg/l)
Arsenic	5.0	0.039	<0.005 - 0.034	5.0	0.12 - 0.35
Barium	100.0	0.350	0.14 - 0.44	100.0	0.11 - 2.25
Cadmium	1.0	0.020	<0.001 - 0.024	1.0	<0.05
Chromium	5.0	0.030	<0.002 - 0.11	5.0	<0.05 - 0.25
Lead	5.0	0.040	<0.001 - 0.095	5.0	<0.20
Mercury	0.2	0.006	<0.0002 - 0.007	0.2	<0.0002 - 0.012
Selenium	1.0	0.009	<0.01 - 0.03	1.0	<0.02 - 0.22
Silver	5.0	0.040	<0.01 - 0.035	5.0	<0.05 - 0.11

1) Leachate characteristics of initial design mix (1.44:1.0) using Milliken Station fly ash and Petersburg Station FGD sludge

**TABLE 5.9-8  
LEACHATE ANALYSES FOR RCRA TOXIC METALS (1996 DATA)**

Parameter	TCLP Limits (mg/l)	Minimum Concentration (mg/l)	Maximum Concentration (mg/l)
Arsenic	5.0	<0.002	0.009
Barium	100.0	0.27	1.41
Cadmium	1.0	<0.005	0.015
Chromium	5.0	<0.01	0.059
Lead	5.0	<0.001	<0.005
Mercury	0.2	<0.002	<0.002
Selenium	1.0	<0.09	0.015
Silver	5.0	<0.01	<0.01

### LINER EQUIVALENCY

The stabilized sludge is spread, graded, and compacted in phased sections of the landfill. Stabilized sludge placement utilizes the slope method such that positive runoff is maintained from the compacted surface at all times. Material is placed in individual lifts of 12 to 18 inches designed to achieve the in-place density required to obtain the desired strength and permeability. Each lift is placed with a slight pitch to insure positive drainage. Once compacted, it begins to develop internal strength and reduced permeability. Individual lifts are combined to result in a multiple lift ranging from 5 to 20 feet in thickness. Based on strength and permeability results obtained, the landfill would ultimately consist of multiple lifts of low permeability liner grade material.

When considering the effective permeability, the full depth liner is significantly more effective than an equivalent natural soil liner. This can be calculated by using Darcy's Law for one-dimensional flow through a material, discharge  $Q = kiA$ , where  $k$  = coefficient



of permeability,  $i$  = hydraulic gradient, and  $A$  = the cross sectional area through which flow takes place. Darcy's Law is valid only under saturated conditions, which is not likely to occur in a landfill situation. Assuming a 20-foot saturated thickness, the full thickness liner with  $k = 1.0 \times 10^{-6}$  cm/sec has a theoretical leakage rate of 1.0 ft<sup>3</sup>/year (7.5 gals/ft<sup>2</sup>/year) versus a 5-foot natural soil liner with a  $k = 1.0 \times 10^{-5}$  cm/sec which has a theoretical leakage rate of 40 ft<sup>3</sup>/year (300 gal/ft<sup>2</sup>/year). Even reducing the permeability of the 5-foot liner to  $1.0 \times 10^{-6}$  cm/sec, the flow rate is still 30 gal/ft<sup>2</sup>/year, four times greater than the full thickness liner. By design, the full thickness stabilized sludge liner would not likely become fully saturated if positive surface runoff is maintained.

## DESIGN EVOLUTION

During final design discussions and meetings with the NYSDPS and NYSDEC, the possibility of using bottom ash as a French drain under the stabilized sludge was discussed. Due to the anticipated low permeability of the stabilized sludge and the design of the landfill promoting runoff so that hydraulic head on the upper surface is virtually eliminated, there was little expectation of leachate being generated by the stabilized sludge. Nevertheless, an underdrain collection system, utilizing a two-foot layer of bottom ash, was incorporated into the operational design. As designed, the two-foot layer was placed over a five to ten-foot layer of stabilized sludge to relieve any potential leachate head build up on the liner. The drainage layer is equipped with pipes extending from the landfill surface into the bottom ash. These pipes, known as "telltales" are used to indicate any leachate buildup on the liner and, if seeping, are sampled for chemical analysis.

During the first few years of landfill operations, stabilized sludge testing indicated that the sludge was not achieving the permeabilities anticipated during the design phase. Table 5.9-4 provides the results from the long term testing program. A telltale began flowing in 1989, however it is likely the flow is from sideslope drainage into the bottom ash drainage layer, rather than from precipitation infiltrating through the stabilized sludge.

Another result of the inability to achieve the lower permeability values, but also due to solid waste regulatory changes through the 1980s, NYSEG was required to change the initial design to include a clay liner below the stabilized sludge. Phase IC, a 15-acre expansion constructed during 1986, was the first phase of the landfill that required a clay liner. The clay was emplaced and compacted to a thickness of 18-inches and a permeability of  $1.0 \times 10^{-6}$  cm/sec or less.

The clay liner provides a low permeability barrier to any potential leachate migration and also provides an additional ability to attenuate many chemical species that may be

Current landfill design, being used to construct the latest phase, phase IJ, consists of an 18-inch clay liner placed and compacted to a permeability of  $1.0 \times 10^{-7}$  cm/sec or less underlying a two-foot drainage layer of bottom ash underlying a five-foot protective layer of stabilized sludge. A geotextile is placed between each layer to reduce infiltration of the different liner elements into each other.

### 5.9.3 EVALUATION OF LANDFILL PERFORMANCE

The primary method of determining landfill performance with respect to being protective of human health and the environment is a network of ground water monitoring wells. New York State solid waste regulations require a minimum of one upgradient and two downgradient monitoring wells installed in each critical hydrogeologic layer. Wells must be spaced no farther than 500 feet apart on the downgradient edge of a landfill and no further than 1500 feet apart on crossgradient and upgradient edges of a landfill. Monitoring wells at Kintigh SWDA meet those vertical and horizontal spacing requirements.

Ground water is sampled quarterly for field measurements and inorganic analytes. A review of the ground water quality analyses indicates that the hydrogeology and hydrochemistry at site is quite complex and ground water quality is highly variable across the site. Moreover, the bedrock aquifer in the Kintigh area produces highly saline ground water that complicates analysis of water quality data from the site.

Despite the extensive investigations at the site, there had been continued debate as to whether plant operations have impacted ground water at the site until a 1992 investigation utilized techniques that definitely showed that the landfill design was protective of the environment.

As part of the licensing of Kintigh Station, a Ground Water Monitoring Program was established to determine potential impacts of plant operations, including solid waste disposal, on the ground water at the site. The report is submitted annually to the New York State Department of Public Service, which currently has ultimate authority over plant operations. The report, compiled since 1983, one year prior to commencement of plant operations, states that the naturally poor quality ground water at the site make trends difficult to ascertain by standard comparative or statistical review of the analytical data. As there have not been any discernible changes in the ground water quality since before plant startup, the report has consistently concluded that there has not been any degradation of the ground water by landfill operations.

Several studies have been conducted to confirm this conclusion, including a hydrogeologic investigation that included an earth conductivity survey performed from 1987 to 1989 by Malcolm Pimie, Inc. and, most notably, the hydrogeochemical investigation performed by Stearns and Wheeler from 1991 to 1993.

In the Stearns and Wheeler study, three methods of geochemical interpretation were used: isotopic analyses of ground water and dissolved solutes to evaluate mixing and ground water age; chemical equilibrium controls on metal solubility; and scatterplots to evaluate the extent of mixing, if any, between the ground water and leachate. The isotopic analyses of hydrogen, oxygen, sulfur and tritium isotopes in the groundwater near Kintigh demonstrated conclusively that leachate has not impacted shallow or deep ground water systems at the site. In addition, tritium levels measured at the site indicate that the deep, saline ground water is older than the plant facilities, and therefore have not been impacted by leachate. Finally, an investigation of the ground water concentrations

of iron and manganese showed a distinct separation of leachate from natural ground water quality at the site, further supporting the conclusion that leachate has not affected the ground water at the Kintigh SWDA.

#### **5.9.4 CONCLUSIONS AND FUTURE CONSIDERATIONS**

Coal combustion byproduct disposal facilities are required to provide effective waste isolation and containment systems. This may be achieved by physical methods to retard or impede leachate generation and migration or chemical methods to attenuate leachate constituents. A full depth, low permeability stabilized sludge with a low permeability clay liner beneath can achieve both of these objectives. In addition, the liner performance meets the criteria of long life, low permeability, and resistance to degradation by leachate.

A clay-lined, stabilized sludge landfill may not be appropriate for all environmental situations. However, it has been shown that, based on the physical and chemical characteristics of FGD sludge stabilized with fly ash and lime and an appropriate environmental monitoring program, a properly designed clay-lined stabilized sludge landfill can be adequately protective of human health and the environment at a much lower cost than other types of landfill designs.

At Kintigh SWDA, it is difficult to determine the liner requirements in the future. NYSEG has justified a continuation of its existing liner system based on the leachate composition and by demonstrating that leachate is not contributing contaminants to the ground water resources at the plant. The latest expansion is currently being constructed with clay, however, if an alternative fuels program is placed in operation or there is a change of the FGD system to forced oxidation producing saleable gypsum, the landfill liner design may have to be reassessed. In addition, regulatory pressures may force NYSEG to redesign any expansion to comply with more stringent, but not absolutely necessary, design requirements.



## 6.0 ECONOMICS

### 6.1 ECONOMIC PARAMETERS

For purposes of comparison and analysis of the Milliken Station FGD demonstration economics, Table 6.1-1 documents the assumptions used in preparing capital cost estimates for future commercial FGD retrofit applications.

**TABLE 6.1-1  
ECONOMIC PARAMETERS**

ITEM	UNITS	TYPICAL VALUE
Cost of Debt	%	8.5
Dividend Rate for Preferred Stock	%	7.0
Dividend Rate for Common Stock	%	7.5
Debt/Total Capital	%	50.0
Preferred Stock/Total Capital	%	15.0
Common Stock/Total Capital	%	35.0
Income Tax Rate	%	38.0
Investment Tax Credit	%	0.0
Property Taxes & Insurance	%	3.0
Inflation Rate	%	4.0
Discount Rate (With Inflation)	%	7.93
Discount Rate (Without Inflation)	%	3.744
Escalation of Raw Materials Above Inflation	%	0.0
Construction Period	Years	1.5
Allowance for Funds Used During Construction	%	3.8
Construction Downtime	Days	90
Remaining Life of Power Plant	Years	15
Year for Cost Presented In This Report	-	1995
Royalty Allowance (Based On Total Process Capital)	%	NA
Capital Charge Factor		
	Current Dollars	-
	Constant Dollars	-
		.1604
		.124
O&M Cost Levelization Factor		
	Current Dollars	-
	Constant Dollars	-
		1.293 <sup>1</sup>
		1.000
Power Plant Capacity Factor	%	65
Sales Tax Rate	%	5.0
Cost of Freight for Process Equipment	%	2
General Facilities/Total Process Capital	%	10.0
Engineering and Home Office Fees/Total Process Capital	%	10.0

<sup>1</sup> The O&M default parameter is 1.314.

The values in Table 6.1-1 are consistent with the default parameters used in recent studies of CCT processes at FETC, as outlined in the General Guidelines for the Project Performance and Economics Report.

## 6.2 ESTIMATED PROCESS CAPITAL COSTS

The total capital requirements for an equivalent 300 MWe net commercial unit incorporating the Milliken Station FGD technologies have been developed using DOE's standardized approach in order to facilitate economic comparisons with other DOE CCT projects. The underlying basis of the capital costs for a mature commercial equivalent of the FGD elements of the Milliken demonstration project are the installed costs for equipment for the Milliken Station CCT demonstration project. Since the equipment utilized at the Milliken Station in many cases serviced one (or both) of the two existing 150 MW units, it was necessary to adjust the quantities of many of the project's components in order to normalize the commercial plant scope of supply, and to scale costs to allow for the differences in both capacity and performance.

It should be noted that the bases of the values in Table 6.2-1 are retrofit costs, and therefore no "retrofit" adjustments are applicable. Also, process contingency is inherent in each cost area, since the costs are based on incurred values of commercially available equipment. The costs supporting the values in Table 6.2-1 are shown in detail by area in Appendix B. The nominal year of costs for the equipment identified in Appendix B is 1995; in reality, these values reflect mixed year dollars, as the cost bases were expended over the project's 27 month procurement and construction schedule during a low inflationary period. The plant equipment values are escalated to 1998 dollar values for the 300 MW commercial plant analyses presented below.

**TABLE 6.2-1  
TOTAL FGD SYSTEM CAPITAL REQUIREMENT  
300 MW COMMERCIAL PLANT**

Area No.	Total Installed Equipment Cost	\$10 <sup>6</sup>	\$/kW
100	Limestone Handling & Prep.	5.3	17.7
800	Slurry Feed & Recycle	3.7	12.2
800	Absorber Module & Auxiliaries	5.6	18.5
1100	ID Fan & Ductwork	6.3	21.1
1100	Stack & Flues	2.5	8.3
1300	Gypsum Dewatering & Handling	4.2	14.1
1400	Waste Water Processing System	2.4	7.9
1500	Other Mechanical Systems	4.7	15.8
1500	Electrical & I&C	5.6	18.7
1500	FGD Building & Site Work	13.4	44.7
<b>A</b>	<b>Total Process Capital</b>	<b>53.7</b>	<b>179.0</b>
B	General Facilities		
C	Engineering & Home Office Fees @ 10% of A	5.4	17.9
D	Project Contingency (10% of A+B+C)	5.9	19.7
<b>E</b>	<b>Total Plant Cost (A+B+C+D)</b>	<b>65.0</b>	<b>216.5</b>
F	Allowance for Funds During Construction (1.9% of E)	1.2	4.1
<b>G</b>	<b>Total Plant Investment (E+F)</b>	<b>66.2</b>	<b>220.7</b>

**TABLE 6.2-1**  
**TOTAL FGD SYSTEM CAPITAL REQUIREMENT**  
**300 MW COMMERCIAL PLANT**

Area No.	Total Installed Equipment Cost	\$10 <sup>6</sup>	\$/kW
H	Royalty Allowance		
I	Preproduction Costs	2.3	7.7
J	Inventory Capital	.51	1.7
K	Initial Catalyst & Chemicals		
<b>L</b>	<b>Subtotal Capital (G+H+I+J+K)</b>	<b>69.0</b>	<b>230.1</b>
M	Cost of Construction Downtime	21.0	70.2
<b>N</b>	<b>Total Capital Requirement (L+M)</b>	<b>90.0</b>	<b>300.3</b>

As Table 6.2-1 indicates, the total capital requirement for an FGD retrofit for a 300 megawatt commercial plant, equivalent in technical scope to Milliken Station, is estimated to be approximately \$90 million, with a corresponding cost per kW of \$300. However, this value does not reflect a completely normalized scope, or adjustments for site/project specific costs. Some possible scope differences affecting costs could include the following: full scope versus partial scope for sorbent and gypsum or sludge handling systems; sparing of the absorbers; production of marketable by-product; design sulfur removal efficiency; design coal, and the reference year of the reported costs (mixed year dollars over several-year periods).

### 6.2.1 ECONOMIC SENSITIVITIES

As indicated in Figure 6.2-1, when plotted against plant size the total costs of the FGD system are shown to increase, as expected. Total Capital Requirements for a FGD retrofit similar to the Milliken Station installation can be expected to range from \$58 million for a 150 MW plant to \$130 million for a 500 MW plant.

When plotted in \$/kW vs. unit size, as shown in Figure 6.2-2, total cost trends decrease markedly, demonstrating a clear and significant economy of scale. On a cost per kW basis, Total Capital Requirements for a FGD retrofit similar to Milliken Station can be expected to range from 385\$/kW for a 150 MW plant to 260\$/kW for a 500 MW plant.



Figure 6.2-1

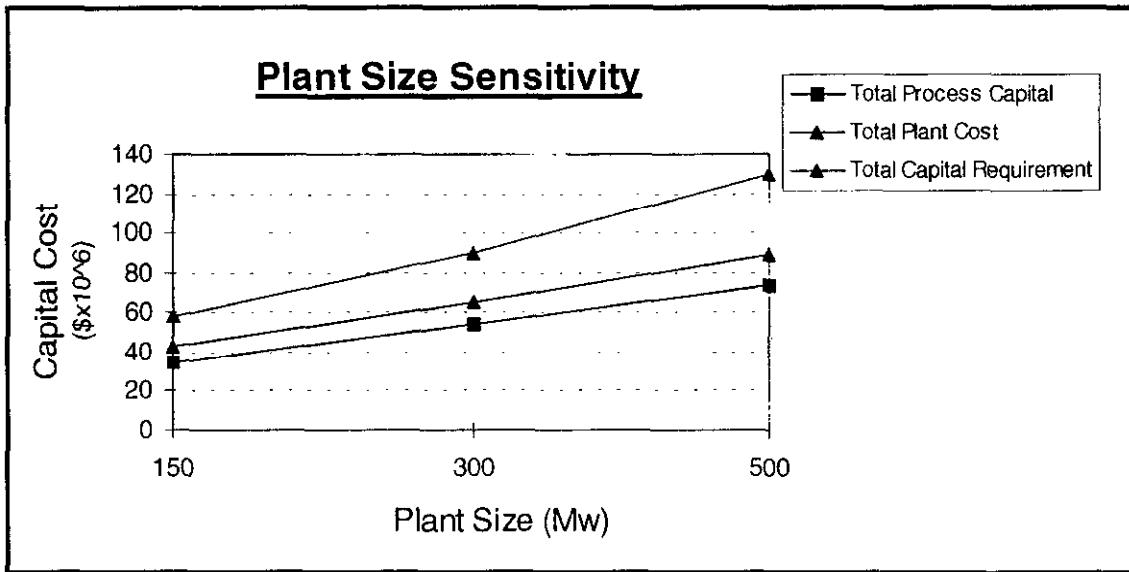
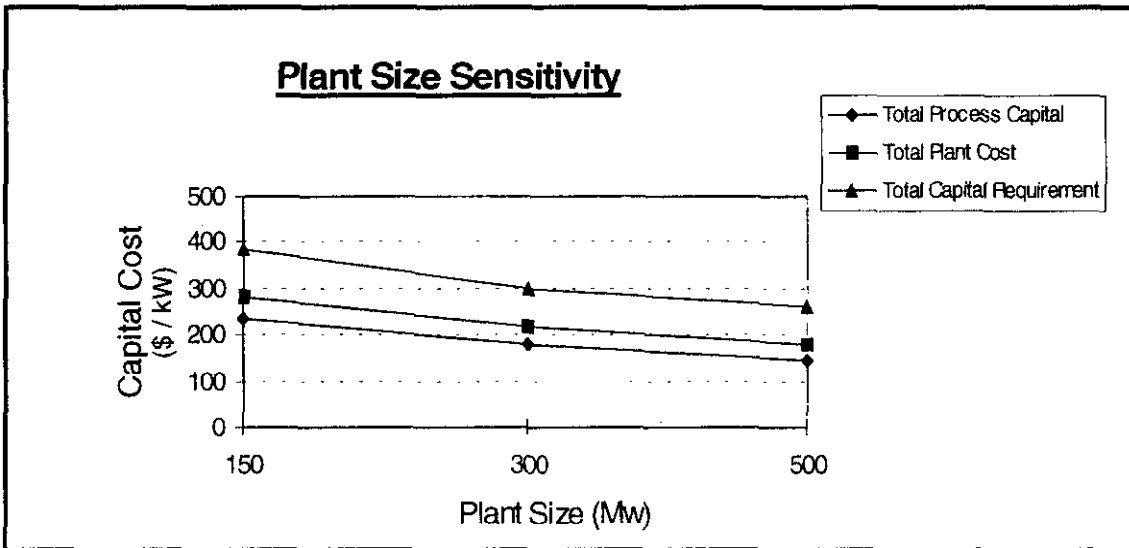


Figure 6.2-2



### 6.2.2 Equipment List

An Equipment List identifying major components and their operating parameters is provided for reference in Appendix A.

### 6.3 PROJECTED OPERATING AND MAINTENANCE COSTS

Fixed operating and maintenance costs include estimates of operating labor, maintenance labor, administration and support and the operating and maintenance materials required for the FGD facilities.

The estimated fixed and variable operating costs for a 300 MW FGD retrofit project comparable to that of Milliken Station are presented below in Table 6.3-1. As indicated in Table 6.3-1, total operations and maintenance costs for a commercial 300 MW FGD retrofit application are approximately \$4.62 million. The following parameters have been assumed in determining O&M costs for the 300 MW commercial plant:

Capacity Factor	65.0%
Plant Life	15 Years
Sulfur In Coal	3.2%
Removal Efficiency	95.0%

**TABLE 6.3-1  
OPERATING & MAINTENANCE COST  
300 MW Commercial Plant**

FIXED O&M COSTS	UNITS	QUANTITY	\$/UNIT	\$10 <sup>6</sup> /YR
Operating Labor	Man hr/hr	26,280	23.00	.6
Maintenance Labor				.26
Maintenance Material				.39
Administration/Support Labor				.26
<b>Subtotal Fixed Costs</b>				<b>1.51</b>
<b>VARIABLE OPERATING COSTS</b>				
Fuels				
N/A	Ton			
Sorbent				
Limestone	Ton	65,043	15.00	.98
Chemicals/Catalyst				
Formic Acid	lbs.	193,596	.43	.08
Utilities				
Electric Power	kW	46	.05	2.3
By-Product Credits				
Gypsum	Ton	114,831	3.00	(0.34)
Calcium Chloride	Ton		1.00	0
Flyash	Ton			
Waste Disposal Charges				
Lime	Ton	1,110	80.82	.009
Sludge Removal	Ton	413	10.00	.000
<b>Subtotal Variable Cost</b>				<b>3.11</b>
<b>TOTAL O&amp;M COST (FIXED + VARIABLE)</b>				<b>4.62</b>

*Operating labor costs* are calculated as the product of the number of hours per year, based on the number of operators per shift, and the operating labor pay rate. It is assumed that the FGD facilities will require the equivalent of three operators per shift.

*Annual maintenance cost* is calculated as a percentage (1%) of the total process capital cost. The value derived from this percentage is then apportioned between maintenance labor and maintenance materials based on a ratio of 40% labor and 60% material.

*Administrative and support labor* is calculated as a percentage (30%) of the sum of operating and maintenance labor.

*Variable O&M* includes the cost of all chemicals and sorbents used in the FGD process, mainly formic acid and limestone, and the cost of disposal of waste products.

Limestone costs are a product of the quantity of limestone and the sorbent's average unit cost. The limestone quantity is determined as the product of the reference plant process design flow times the net power produced, removal efficiency and the sulfur content of the coal feed.

Similarly, formic acid costs are the product of the quantity of formic acid used times the chemical's expected unit cost. The formic acid quantity is calculated as the product of the reference plant process design flow times the amount of SO<sub>2</sub> removed, divided by the amount of SO<sub>2</sub> removed at design conditions.

Because the FGD process creates a high quality gypsum by-product, a credit for sale of gypsum is realized. However, note that the current analysis excludes other potential operating credits obtained from the sale of flyash, bottom ash and calcium chloride.

Waste disposal costs are based on landfill disposal costs for lime and sludge produced in the FGD process. The disposal quantities are calculated as the product of the reference plant process design flow times the net power produced, divided by plant net generation.

## 6.4 SUMMARY OF PERFORMANCE AND ECONOMICS

The following Table 6.4-1 summarizes the performance and economics of the FGD processes implemented at Milliken Station as part of the CCT demonstration project, as applied to a 300 MW commercial power plant. The performance figures include emissions of SO<sub>2</sub> both before and after controls. Process economics are expressed in both current dollars, which includes the effect of inflation, and a constant dollar basis, which ignores inflation.

**TABLE 6.4-1  
SUMMARY OF PERFORMANCE AND ECONOMICS  
COMMERCIAL 300 MW POWER PLANT**

Power Plant Attributes		Units	Value			
Plant Capacity, Net		MWe	300			
Power Produced, Net		10 <sup>9</sup> kWh/yr	1.708			
Capacity Factor		%	.65			
Plant Life		yr	15			
Coal Feed		10 <sup>6</sup> tons/yr	.629			
Sulfur In Coal		wt %	3.2			
Emissions Control Data		Units	SO <sub>2</sub>	NO <sub>x</sub>	TSP	PM <sub>10</sub>
Removal Efficiency		%	95.0			
Emissions Standard		lb/10 <sup>6</sup> BTU	1.20			
Emissions Without Controls		lb/10 <sup>6</sup> BTU	5.01			
Emissions With Control		lb/10 <sup>6</sup> BTU	0.25			
Amount SO <sub>2</sub> Removed		tons/yr	38,268			
		Current Dollars		Constant Dollars		
Levelized Cost of Power		Factor	Mills/kWh	Factor	Mills/kWh	
Capital Charge		0.1604	8.46	0.124	6.54	
Fixed O&M Cost		1.293	1.15	1.000	0.89	
Variable Operating Cost		1.293	2.35	1.000	1.82	
Total Cost			11.96		9.24	
Levelized Cost -SO <sub>2</sub> Basis		Factor	\$/ton removed	Factor	\$/ton removed	
Capital Charge		0.1604	377.56	0.124	291.88	
Fixed O&M Cost		1.293	51.13	1.000	39.55	
Variable Operating Cost		1.293	105.03	1.000	81.23	
Total Cost			533.72		412.66	
Levelized Cost -SO <sub>2</sub> + NO <sub>x</sub> Basis		Factor	\$/ton removed	Factor	\$/ton removed	
Capital Charge		0.160	NA	0.124	NA	
Fixed O&M Cost		1.314	NA	1.000	NA	
Variable Operating Cost		1.314	NA	1.000	NA	
Total Cost			NA		NA	

The economics for the 300 MW commercial facility are presented as levelized current or constant costs calculated over the remaining life of the plant. The economic factors are

based on reference parameters established by DOE to facilitate comparison with other CCT projects.

In summary, the 300 MW base case unit capital and first year O&M (in 1998 dollars) are \$90 million, (\$300kW) and \$4.54 (\$15kW) million respectively. Levelized costs for the base case 300 MW unit are \$534/ton SO<sub>2</sub> removed on a current dollar basis, and \$413/ton SO<sub>2</sub> removed on a constant dollar basis. Busbar cost is 11.96 mills/kWh on a current dollar basis and 9.24 mills/kWh on a constant dollar basis.

## 6.5 EFFECT OF VARIABLES ON ECONOMICS

### 6.5.1 S-H-U

Parametric calculations have been performed utilizing a computer-based model on the 300 MW commercial plant's costs presented in section 6.4 in order to determine how annual levelized costs (in \$/ton of SO<sub>2</sub> removed) would vary with key process variables, including capacity factor, plant book life and sulfur content of the coal feed. The results of these analyses are summarized in Table 6.5-1, with graphical presentations provided in Figures 6.5-1, 6.5-2, and 6.5-3 which demonstrate sensitivities related to changes in capacity factor, plant life and sulfur content of coal, respectively.

**Table 6.5-1**  
**Sensitivity Analysis**  
**300 MW Commercial Plant**

Capacity Factor	\$/Ton SO <sub>2</sub> Removed	Plant Life	\$/Ton SO <sub>2</sub> Removed	Sulfur Content	\$/Ton SO <sub>2</sub> Removed
50%	633	10	601	1.0%	1650
65%	534	15	534	3.2%	534
80%	472	20	506	4.0%	432

**Figure 6.5-1**

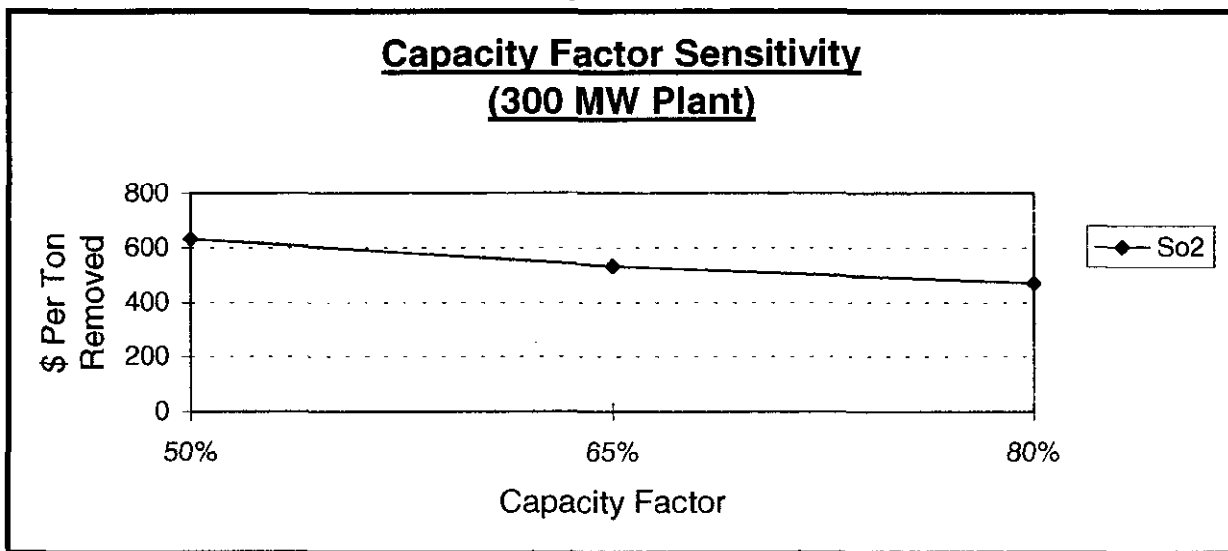


Figure 6.5-2

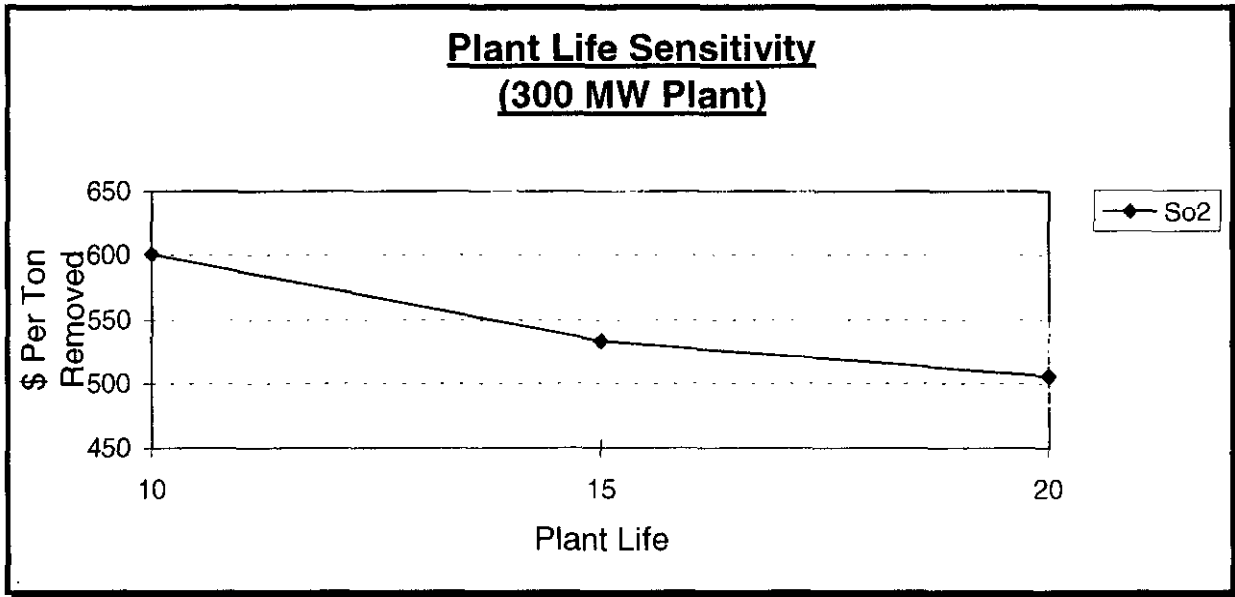
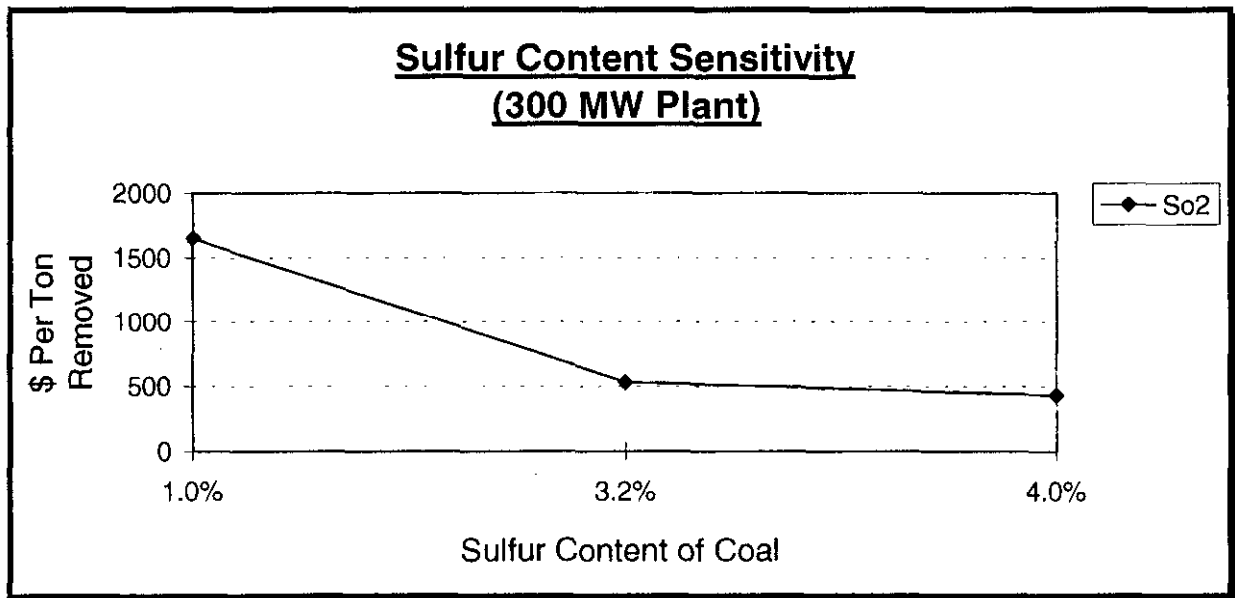


Figure 6.5-3



## 7.0 COMMERCIALIZATION



## **7.0 COMMERCIALIZATION POTENTIAL AND PLANS**

The purpose of this section is to address the issues of the commercial readiness of the demonstrated technologies and the plans for their commercialization. Four technologies demonstrated at Milliken Station provide the bases for this discussion: the S-H-U FGD system; the Stebbins tile absorber; the ABB heat pipe; and the DHR Plant Economic Optimization Advisor (PEOA™). In order to assess the commercialization potential of each demonstrated technology it is important to analyze their potential markets. The market analysis for each technology includes sections which address the applicability of the technology and which assess the potential size of the market for each technology over the next five to ten years and over the next 25 years and the share of that market the technologies could capture under favorable circumstances. The market analysis also includes a discussion of barriers to market penetration and an analysis of the competitive position of each demonstrated technology. The commercialization strategy for each technology is discussed including who will lead the marketing effort, what type of organization will be formed, what market niche will be approached first, and what geographical areas are being considered.

A detailed market analysis and discussion of commercialization plans was presented for each technology in the Commercialization Concept Proposal, Volume III of the Project's response to DOE PON Number DE-PS01-91FE 62271, which is included by reference. Copies of this document can be obtained upon request from DOE. Much of this material was also included in Section 1.4 of the Public Design Report which is also included by reference. Copies of this document can also be obtained upon request from DOE. Accordingly, this Project Performance and Economics Report will address the commercialization potential and plans in brief summary fashion only.

### **7.1 SHU FGD TECHNOLOGY**

#### **MARKET ANALYSIS**

A key factor in the commercialization of FGD technology is that the market is driven by the rate of growth in the electric power industry and by the demands of the regulatory environment. Public Law 101-549, the 1990 Clean Air Act Amendment (CAAA), requires existing coal-burning power plants to reduce sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) emissions. Considering the technology options which are commercially available today, it appears that a significant portion of these existing plants will have to rely on wet flue gas desulfurization (FGD) and NO<sub>x</sub> mitigation upgrades to reach the levels of SO<sub>2</sub> and NO<sub>x</sub> required by legislation. In addition, the SO<sub>2</sub> emissions credit trading feature of the Clean Air Act Amendments places greater emphasis on ultra-high cost effective SO<sub>2</sub> removal capability. The ultra-high SO<sub>2</sub> removal capability of the SHU process, i.e., up to 98 percent SO<sub>2</sub> removal (as demonstrated by the MCCTD Project), is thus a significant selling feature.

Competing lime and limestone-based flue gas desulfurization processes produce large quantities of solid waste byproducts. The waste produced by many of these technologies has no commercial value and must be landfilled. The SHU process can produce commercial grade, as opposed to disposable grade, gypsum by washing the gypsum for chloride and formic acid removal during dewatering. The SHU process produces a 100 percent yield of high quality gypsum crystals suitable for the wallboard or cement industries. As suitable landfill sites become harder to find and as the costs of landfilling large quantities of power plant waste rise, processes such as SHU which can economically produce a marketable byproduct should have a significant competitive advantage.

Competing lime and limestone-based flue gas desulfurization processes impose significant auxiliary power requirements on the host power plant, resulting in lower station heat rates and increased greenhouse gas emissions per unit of net power generation. The SHU process offers reduced auxiliary power consumption compared to some competing processes due to more efficient oxidation, lower L:G ratio, increased limestone utilization, absence of gypsum fines, and lower gas-side pressure losses. As deregulation forces more rigorous economic competition among power generators and as concerns regarding the global buildup of greenhouse gases begins to affect the marketplace, these competitive advantages of the SHU process should be reflected in increased marketability.

While Saarberg-Hölter Umwelttechnik GmbH, a German company, owns the SHU process license and will supply the basic process engineering, a majority of detailed design services and all equipment will be supplied by U.S. companies. This will aid in the development of the U.S. manufacturing base that will be supplying the process to the US power industry.

The SHU process is a highly cost competitive FGD process. Preliminary evaluations reported in EPRI GS7193, Economic Evaluation of FGD Systems, which was published in 1991, indicated that SHU technology may be the most cost competitive of the FGD processes for achieving high SO<sub>2</sub> removal rates with a limestone-based system. With the MCCTD project's confirmation of this expected cost savings, the SHU process should capture a large share of the US FGD market due to requirements for retrofit or new plant SO<sub>2</sub> emission controls.

## **APPLICABILITY OF THE TECHNOLOGY**

The SHU technology has wide-spread application within the utility and industrial market. With slight modification, this process has been used in Europe to successfully reduce SO<sub>2</sub> emissions generated from boilers fired with coal, lignite, oil, and gas; industrial boilers; and also in municipal waste incinerators. This process also has the potential for use in reducing SO<sub>2</sub> emissions associated with coal gasification, shale oil retorting, and Orimulsion. The process is applicable to boilers firing low, medium or high sulfur coals,

without limits as to boiler size or type, providing SO<sub>2</sub> removals of up to 98%. As with any wet limestone FGD process the SHU technology requires a significant amount of plot space on site, though the amount of space required can be minimized by adoption of the split module, below-stack configuration demonstrated by the MCCTD project.

## **MARKET SIZE**

A fully detailed analysis of the potential FGD market is provided in Volume I of the *Public Design Report*. The results of this analysis are summarized in tables 7.1-1 and 7.1-2. In this analysis the total U.S. electric market available to the SHU process was divided into two segments - retrofit capacity and new capacity. For retrofit FGD technology, the total U.S. market was limited to all pre-NSPS coal-fired boilers that are presently in commercial service, and are not equipped with SO<sub>2</sub> control (i.e., FGD, physical coal cleaning, atmospheric fluidized-bed combustion repowering, or compliance low-sulfur coal). New capacity included all projected coal fired additions through the year 2030.

The analysis forecast a large market share of both retrofit and new capacity plants for the SHU FGD process. Initially, this market would be stimulated by electric utility power plants requiring FGD retrofit to comply with Clean Air Act Amendment legislation, with plants responding to this legislation with applications starting in 1995. It was assumed that the retrofits would continue for a finite period, 15 years. As a result of the MCCTD project, the SHU technology would be fully commercialized by 1999. The analysis assumed that the SHU process would be able to penetrate the new United States power plant market by 1996.

Table 7.1-1 shows the calculated market share of the SHU FGD process compared with existing FGD for the retrofit power plant market. A projection of 35 years, from 1996 to 2030, is presented in five year increments. Each year's fractional shares depends on the previous year's fractional shares. This means that an initial market share for the new SHU technology is required and must be assumed to stimulate a market. A 1.5 percent share was assumed. This is considered realistic in that it shows that an outside force, such as the Milliken project or an initial investment, is needed before the product becomes accepted.

Table 7.1-2 depicts the calculated new power plant market shares for the SHU FGD process. The shares differ from those of the retrofit market due to several factors, such as different relative capital costs and the growth of new power generation in the time frame of interest. Note that the total market share for FGD systems diminishes as it is displaced by other advanced technologies.

Based on this analysis, projected SHU FGD market share for retrofits in the U.S. through the year 2030 totals 5,700 MW. The projected SHU FGD market share in the U.S. for new power plants through 2030 totals 96,200 MW. The balance of the retrofit and selected new power plant markets will use other available sulfur reduction technologies.

**TABLE 7.1-1**

**MARKET ASSESSMENT SUMMARY:  
RETROFIT CAPACITY MARKET PENETRATION  
FOR ADVANCED SHU TECHNOLOGY FROM YEAR 1995 THROUGH 2030**

	Estimated SHU Penetration (MW)	Relative* Penetration (% of Market)
1996-2000	607	2.0%
2001-2005	1188	3.5%
2006-2010	1600	5.9%
2011-2015	1348	9.7%
2016-2020	583	15.6%
2021-2025	186	23.9%
2026-2030	154	34.8%

\* Relative to total population

**TABLE 7.1-2**

**MARKET ASSESSMENT SUMMARY:  
NEW CAPACITY MARKET PENETRATION  
FOR ADVANCED SHU TECHNOLOGY FROM YEAR 1996 THROUGH 2030**

	Estimated SHU Penetration (MW)	Relative* Penetration (% of Market)
1996-2000	1314	1.9%
2001-2005	3059	3.3%
2006-2010	5824	5.3%
2011-2015	12146	8.5%
2016-2020	21612	13.3%
2021-2025	27323	20.3%
2026-2030	24960	30.0%

**MARKET BARRIERS**

US utilities are reluctant to invest in a technology which remains unproven within the US, where fuels and operating conditions generally differ. Further, some US companies are reluctant to purchase equipment from international suppliers. However, the successful demonstration at Milliken Station, in conjunction with SHU's experience in Europe, will enable SHU to effectively market the FGD technology in the US, through its US design and manufacturing partners.

**ECONOMIC COMPARISONS WITH COMPETING TECHNOLOGIES**

Variations in FGD system design requirements, process economics, complexity, as well as unique site and project characteristics serve to make FGD technology comparisons a challenging task. In this study, the capital, operating and maintenance costs of several competing FGD systems have been evaluated, and compared on the basis of leveled busbar costs and the total cost of SO<sub>2</sub> removed. Three approaches have been utilized to

demonstrate comparisons between the Saarberg-Holter w/Wallboard Gypsum technology with competitive FGD systems: 1) Comparisons based on published values for various FGD applications; 2) Use of the EPRI FGDCOST Cost Estimating Model to compare competing technologies on a normalized basis; and 3) Comparisons with advanced technologies.

Wet processes are the class of FGD technology with the largest installed experience base. Wet FGD, and some other competing technologies, have high (90 percent), or, as in the case of SHU, very high (95+ percent) proven sulfur removal capability. Unfortunately, some types of wet FGD (other than SHU), have sensitive control requirements that make operations difficult and sensitive, particularly during load changes and plant transients; scaling deposits and plugging have been a persistent problem, and overall reliability of wet FGD equipped units has therefore suffered. The unique features of the SHU process either eliminate or mitigate these problems that are of concern in many other FGD processes. There are many wet FGD processes, some new and some commercially-established. These include:

- SHU wet flue-gas desulfurization.
- Conventional limestone wet flue-gas desulfurization.
- Conventional lime wet flue-gas desulfurization.
- Limestone forced-oxidation wet flue-gas desulfurization.
- Magnesium (Thiosorbic) lime wet flue-gas desulfurization.
- Magnesium oxide wet flue-gas desulfurization.
- Wet FGD with inhibited oxidation (Thiosulfate or elemental sulfur).
- Dual-Alkali wet flue-gas desulfurization.
- Bechtel CT-121 wet flue-gas desulfurization.
- Soda Ash wet flue-gas desulfurization.
- Dowa wet flue-gas desulfurization.
- Wellman-Lord (Sulfur) wet flue-gas desulfurization.
- Ispra (Sulfur) wet flue-gas desulfurization.
- SOXAL.
- Other regenerative systems.

The Electric Power Research Institute (EPRI) has completed an evaluation of 24 competing FGD processes. This evaluation found that the capital costs of SOXAL, Wellman-Lord, and other regenerable FGD processes are greater than the capital cost of wet limestone scrubbing. The evaluation found that the levelized total annual revenue

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requirements and parasitic energy consumption of the regenerable processes (SOXAL, Wellman-Lord, et. al.) were also greater than limestone wet scrubbing. The SHU process advantages, when compared to regenerable FGD processes include: lower energy consumption, lower capital and total annual operating costs, and minimal solid waste and scrubber blowdown production.

### **Comparative FGD Technologies**

The technologies most often considered to provide sulfur emission reductions in U.S. power plants include the following:

- Wet flue gas desulfurization (FGD), the class of technology in which the SHU process belongs
- Furnace sorbent injection
- Economizer sorbent injection
- Duct sorbent injection with either lime or sodium sorbent
- Tampella Process sulfur removal
- Lurgi circulating fluidized bed sulfur removal
- Fluidized bed combustion technologies
- Lime spray dryer sulfur removal
- Combined NO<sub>x</sub>/SO<sub>x</sub> Control Technologies, such as: NOXSO, Degussa, Haldor Topsoe, Electron Beam, and SNRB
- Pre-combustion sulfur control technologies, such as deep coal cleaning. Here, however, fuel cost becomes high, and only modest levels of sulfur removal are economically practical.

Table 7.1-3 presents the results of an investigation into the costs of FGD technologies. The data summarized in Table 7.1-3 has been obtained from publicly available documents, primarily published results from the Clean Coal Technology program. Since retrofit issues vary widely due to the unique aspects of each site and plant, the results of this investigation, as can be expected, demonstrate a wide range of FGD retrofit costs. It should be noted that no attempt has been made to normalize the scope of the comparative projects in order to achieve a normalized cost basis. Costs vary due to the demonstration plants' site specific conditions, the technologies applied, plant size, availability and efficiencies, as well as individual study approaches and methodologies. Although the results of this investigative approach are inconclusive, the S-H-U FGD system with tile absorber appears to fall within a competitive cost range for systems limited strictly to flue gas desulfurization, particularly when efficiency is considered as part of the comparability equation.

**Table 7.1-3**  
**Comparative FGD Technologies**  
 (Based on Published Literature)

	<b>S-H-U FGD W/Tile Absorber</b>	<b>Pure Air Advanced FGD</b>	<b>LIFAC Sorbent Injection</b>	<b>AirPol Gas Suspension Absorber</b>	<b>Wet Limestone Forced Oxidation (Typical)</b>	<b>Confined Zone Dispersion</b>
Plant Size (MW)	300	500	300	300	300	500
Capacity Factor	65%	65%	NA	100%	100%	65%
Book Life	15	15 Years	NA	15	15	30
Coal Feed (%S)	3.2%	3.0%	2.8%	2.6%	2.6%	3.9%
Total Process Capital (\$/kW)	\$179	\$80	NA	\$91	\$144	NA
<b>Total Capital Requirement (\$/kW)</b>	<b>\$300</b>	<b>\$111</b>	<b>\$66</b>	<b>\$149</b>	<b>\$216</b>	<b>\$38</b>
<b>SO2 Removal Efficiency (%)</b>	<b>95%</b>	<b>90%</b>	<b>70%</b>	<b>90%</b>	<b>90%</b>	<b>50%</b>
Levelized busbar cost (Current Mills/kWh)	11.96	8.65	NA	10.35	13.0	NA
<b>Annual Levelized Cost (Current \$/ton SO2 Removed):</b>						
Capital Charge	\$377	\$142	NA	\$291	NA	NA
Fixed O&M	\$51	Included	NA	\$129	NA	NA
Variable O&M	<u>\$105</u>	<u>\$103</u>	<u>\$65</u>	<u>\$182</u>	<u>NA</u>	<u>NA</u>
Total	\$533	\$245	NA	\$602	NA	\$384
<b>Year of Costs</b>	<b>1995</b>	<b>1995</b>	<b>1993</b>	<b>1990</b>	<b>1990</b>	<b>1993</b>
<b>NOTES</b>	1)Produces Salable Gypsum Product.	1)Produces Salable Gypsum Product. 2)Capital Charge includes Fixed O&M Charges			Raytheon Evaluation as part of AirPol Study	

### Alternatives to FGD Retrofit Technology

In addition to the technologies listed above, most of which are amenable to retrofit, there are other economic choices that become strong competitors when considering existing plant upgrade/retrofit for reduced sulfur emissions. For the retrofit market of existing coal-fired plants, options include:

- Retire the unit, and either bulk purchase power or replace with clean new capacity;
- Do nothing, controlling sulfur in other units, accepting low capacity factor and retirement prior to any requirement for mandated sulfur control;

- Switch to a low sulfur coal or co-fire with natural gas or other clean fuel, accepting moderate sulfur emission levels, potentially higher fuel cost, possible derate, and possible need for particulate control upgrade;
- Switch to natural gas or other low sulfur fuel, accepting high fuel cost, and possible vulnerability to future fuel supply curtailment; or
- Repower with a cleaner combustion technology (e.g. AFBC) or repower with a topping cycle (e.g. integrated gasification combined cycle) technology.
- Develop an SO<sub>2</sub> allowance trading strategy. The market-based allowance trading system capitalizes on the power of the market to reduce SO<sub>2</sub> emissions cost.

### **EPRI FGDCOST: COST ESTIMATING MODEL**

The EPRI FGDCOST: Cost Estimating Model was used to develop comparative capital costs for nine currently available FGD processes:

- a) Limestone forced-oxidation/Throwaway Gypsum
- b) Limestone forced-oxidation/Wallboard Gypsum
- c) Magnesium Enhanced Lime
- d) Thiosulfate/Inhibited Oxidation Limestone
- e) DBA Enhanced Limestone
- f) Pure Air - Cocurrent Scrubber
- g) CT 121
- h) Lime Spray Dryer
- i) Saarberg-Holter (SHU)

Descriptions of each of the FGD systems selected for evaluation are presented in the EPRI FDGCOST model's documentation manual, and are reprinted below:

- *Limestone with forced oxidation producing a wallboard gypsum byproduct* is the base case FGD system. This system uses a limestone slurry in an open spray tower with in-situ oxidation to remove SO<sub>2</sub>, and forms the gypsum product by washing the solids from the recycle tank.
- The *limestone with forced oxidation* system uses a limestone slurry in an open spray tower with in-situ oxidation to remove SO<sub>2</sub> and form a gypsum sludge.
- In the *magnesium enhanced lime* system a magnesium and calcium sulfate solution is used in an open spray tower and form a calcium sulfite rich sludge. The magnesium sulfite is regenerated in the reaction tank liquor forming the calcium



sulfite. The make-up for magnesium lost with the solid product is supplied with the reagent lime.

- The *thiosulfate/inhibited oxidation limestone* process is similar to the limestone forced oxidation system in that a limestone slurry is used in an open spray tower to remove SO<sub>2</sub>. Instead of oxidizing the sulfite product, however, emulsified sulfur is added to the limestone slurry, forming thiosulfate which inhibits sulfite oxidation.
- In the *limestone with DBA* system, as a modification to the limestone forced oxidation process, DBA (dibasic acid) is added to act as a buffer/catalyst in the open spray tower where a limestone slurry absorbs the SO<sub>2</sub> and forms a calcium sulfite/sulfate sludge.
- The *Pure Air* system sprays a limestone slurry into a co-current, downflow grid packed absorber to remove SO<sub>2</sub>. An air rotary sparger system is used to provide agitation as well as forced oxidation to yield a gypsum sludge.
- The *CT-121* process uses a limestone slurry in a jet bubbling reactor to remove SO<sub>2</sub> and oxidize the reaction products to form calcium sulfate.
- The *lime spray dryer* system is a semi-dry process in which the flue gas is contacted with lime slurry in a spray dryer absorber. The slurry reacts with SO<sub>2</sub> to form a solid which is collected in a baghouse or electrostatic precipitator along with the flyash.
- The *Saarberg-Holter (SHU)* system uses a calcium carbonate/sulfate slurry in a cocurrent/countercurrent gas flow absorber to absorb SO<sub>2</sub>. Formic acid is added to the slurry to buffer the solution and control the pH drop in the absorber, enhancing SO<sub>2</sub> removal. While this is the basic technology applied at Milliken Station, in the FGDCOST model this technology option does not include the tile absorber application or the saleable gypsum byproduct that exemplifies the Milliken demonstration project.

### **Approach to Use of FGDCOST: Cost Estimating Model**

Key features of the FGDCOST cost estimating model include:

- Ability to compare various process capital and control costs by using the same design basis.
- Cost versus capacity equations that allow the models to cost equipment as sizes change based on input parameters.
- Development of total levelized operating and control costs in mills/kWh and \$/ton SO<sub>2</sub> removed by combining operating and maintenance costs with capitalized investment costs.
- Ability to run sensitivity analyses for variations in economic design criteria.

The variables in the EPRI model include plant technical input, technical inputs for the plant boiler, technical inputs for the FGD system, and economic inputs. Plant technical input data includes the plant gross and net MW rating, gross plant heat rate, and the plant capacity factor. Technical inputs for the boiler include boiler heat input, air heater leakage, and pressure temperature and moisture attributes. The technical inputs for the FGD system include the percentage of SO<sub>2</sub> removed, flue gas temperature data, L/G ratio and other key elements of process chemistry. The technical parameters were applied uniformly to each of the model's modules. Some of the key technical parameters applied, exclusive of default and calculated parameters, are as follows:

#### Key Technical Parameters

Model Parameter	Value
Total Net Plant Rating, MW	300
Gross Plant Heat Rate, NPHR	9,408
Coal Sulfur Content	3.2%
Boiler Heat Input, MMBtu/Hr	2945
Capacity Factor	65%
Removal Efficiency	95%
Plant Life	15 Years

The FGDCOST model's economic inputs include levelized fixed charge rates, discount and AFUDC rates, inflation and project and process contingency rates, as well as specific unit costs for reagents, labor rates, and power and sludge disposal requirements related to the FGD processes. The economic parameters were applied uniformly to each of the model's modules. Some of the key economic parameters applied are as follows:

#### Key Economic Parameters

Model Parameter	Value
Gen. Facilities Capital	20%
Eng. & Home Office Fees	10%
Project Contingency	10%
Process Contingency	0%
AFUDC Rate	3.8%
Discount Rate	7.9%
Levelized Fixed Charge Rate	16.04%

Variable O&M	Unit	Rate
Limestone Cost	\$/Ton	15.00
Utilities	\$/kW	0.05
Gypsum (Credit)	\$/Ton	(3.00)
Lime Disposal	\$/Ton	80.82
Sludge Removal	\$/Ton	10.00
Operating Labor Rate	\$/Hour	23.00

It was important to establish a normalized scope for the Base Case, and uniform technical criteria which could be applied to each technology option evaluated in order to establish a reference basis for comparison. Once a uniform set of technical and

economic parameters was established, observed changes in the model's output could then be determined to be related directly to the modeled differences between the various FGD technologies.

The Base Case is the 300 MW commercial limestone forced oxidation system with a wallboard grade gypsum byproduct. In addition to plant size, other key technical parameters, applicable to all cases in this evaluation, include a capacity factor of 65%; FGD efficiency at 95%; plant life of 15 years; sulfur in coal equals 3.2%; and a base plant heat rate of 9,408 Btu/kWh.

The established technical and economic variables for the 300 MW commercial plant were input to the EPRI FGDCOST model to produce a baseline cost estimate for the limestone with forced oxidation with a gypsum wallboard byproduct system. The cost output from the FGDCOST model for the baseline technology was then reviewed, and adapted to conform with the 300 MW commercial plant cost estimate presented in section 6.2 of this report. As adjusted, the capital cost estimate produced by the model is essentially the SHU system. To fully define the normalized scope, site and project specific cost elements were evaluated. As a result of this evaluation, scope elements and related costs were either added or deleted from the FGDCOST model's baseline estimate.

For example, as part of the effort to normalize the scope of the base case technology, the review of the scope of the FGDCOST model's reagent feed system indicated that some major cost elements, such as a railspur, were not essential to most retrofit applications. Similarly, bulk limestone storage and transfer system requirements as defined for the 300 MW commercial plant were considered to be more applicable to most retrofit cases than the scope presented in the EPRI model. The FGDCOST model's developed costs for this system were therefore factored to agree with the reference commercial plant's costs.

Costs were evaluated similarly for the SO<sub>2</sub> Removal System, Flue Gas System, Byproduct Handling and General Support Equipment. The costs of these systems in the model were also factored to conform to the reference commercial plant's values for these systems.

The value of Other Mechanical Systems was increased in the FGDCOST model's baseline to allow for scope elements such as process piping, cranes and hoists, sumps and drains which were not identified in the FGDCOST model's scope, yet which were considered by the reviewers to be necessary for a complete FGD retrofit. The costs for onsite electrical power requirements were increased to allow for elements such as switchgear, CEMS, DCS and transmitters that did not seem to be included in the FGDCOST model's scope, but which were considered essential to a commercial FGD retrofit.

The value for determining General Facilities' costs was increased in the model's base case scenario from 10% of Total Process Capital to 20%. The General Facilities scope includes the FGD structure and Site Work, and appeared to be undervalued in the FGDCOST model's base case. The normalized FGD scope also allows for a stack constructed at grade level, and appropriate costs for associated ductwork.

The resulting normalized scope and capital cost estimate served as the basis for developing levelized cost values that conform with DOE's requirements, and provided the basis for comparison with competing technologies. To achieve the comparability of costs through the FGDCOST model, the factors applied in the Base Case to achieve the normalized retrofit scope were applied uniformly in each of the selected technology options' modules. The total process capital costs developed by the FGDCOST model were then input into a spread sheet model that developed total capital requirements, total O&M costs and levelized costs in accordance with DOE guidelines.

Table 7.1-4 summarizes the total capital requirements for the Limestone forced-oxidation/Wallboard Gypsum technology. Operations and Maintenance cost for the base case technology are presented in Table 7.1-5, and Table 7.1-6 presents the levelized busbar and SO<sub>2</sub> removal cost bases.

**Table 7.1-4  
Limestone Forced-Oxidation/Wallboard Gypsum**

<b>CAPITAL COSTS (market base)</b>			
	Plant Size (Mw)	300.0	
	Capacity Factor	65.0%	
	<b>FGD System Titles</b>	<b>\$x1,000,000</b>	<b>\$/kW</b>
100	Raw Material Receiving and Handling System	5.3	17.7
200	Fuel Preparation and Storage System	0.0	0.0
300	Fuel and Oxidant Feed Handling System	0.0	0.0
400	Combustion / Steam Generation System	0.0	0.0
500	Combustion Modification Equipment	0.0	0.0
600	Fuel Gas Processing and Handling System	0.0	0.0
700	Power Generating System	0.0	0.0
800	So <sub>2</sub> Removal System	9.2	30.7
900	NO <sub>x</sub> Removal System	0.0	0.0
1000	Particulate Removal System	0.0	0.0
1100	Flue Gas Handling System	5.6	18.5
1200	Raw Material Regeneration System	0.0	0.0
1300	By-Product Processing and Handling System	6.1	20.4
1400	Waste Handling System	0.0	0.0
1500	Common Support Systems	12.8	42.7
1600	Other Systems	6.8	22.6
A	Total Process Capital	45.8	152.7
B	General Facilities		
C	Engineering & Home Office Fees (10% of TPC)	4.6	15.3
D	Project Contingency (10% of A+B+C)	5.0	16.8
E	Total Plant Cost (A+B+C+D)	55.4	184.7
F	Allowance for Funds During Construction	1.1	3.5
G	Total Plant Investment	56.5	188.2
H	Royalty Allowance	NA	NA
I	Preproduction Costs	2.1	7.1
J	Inventory Capital	0.485	1.62
K	Initial Catalyst & Chemicals	NA	NA
L	Subtotal Capital (G+H+I+J+K)	59	197.0
M	Cost of Construction Downtime	21	70
N	Total Capital Requirement	80	267.2

**Table 7.1-5  
Limestone Forced-Oxidation/Wallboard Gypsum**

<u>Fixed O &amp; M Costs</u>	<u>Units</u>	<u>Quantity</u>	<u>\$ / Unit</u>	<u>\$(xM)/Yr</u>
Operating Labor	Mnhr/hr	27,040	23.00	0.62
Maintenance Labor				0.18
Maintenance Material				0.28
Administration / Support Labor				0.24
Subtotal Fixed Costs				1.33
<u>Variable Operating Costs</u>				
Fuels				
n/a	Ton			
Sorbent				
Limestone	Ton	67,929	15.00	1.02
Chemicals/Catalyst				
Formic Acid	Lbs	171,845	0.43	0.07
Utilities				
Electric Power	kW x10 <sup>3</sup>	46	0.050	2.30
By-products Credits				
Gypsum	Ton	123,674	3.00	(0.37)
Calcium Chloride	Ton		1.00	
Flyash	Ton	0	5.33	0.00
Waste Disposal Charges				
Lime	Ton	0	80.82	0.00
Sludge Removal	Ton	0	10.00	0.00
Subtotal Variable Cost				3.02
Total O & M Cost (Fixed + Variable)				4.35

**Table 7.1-6  
Limestone Forced-Oxidation/Wallboard Gypsum**

<u>Power Plant Attributes</u>				<u>Units</u>	<u>Value</u>
Plant Capacity (net)				Mwe	300
Power Produced (net)				10 <sup>9</sup> kWh/yr	1.708
Capacity Factor				%	65.0%
Plant Life				yr	15
Coal Feed				10 <sup>6</sup> tons/yr	0.629
Sulfur in Coal				wt %	3.2%
<b>Emissions Control Data</b>	<b>Units</b>	<b>SO<sub>2</sub></b>	<b>NO<sub>x</sub></b>	<b>TSP</b>	<b>PM<sub>10</sub></b>
Removal Efficiency	%	95.0%			
Emissions Standard	lb/10 <sup>6</sup> BTU	1.20			
Emissions Without Controls	lb/10 <sup>6</sup> BTU	5.01			
Emissions With Controls	lb/10 <sup>6</sup> BTU	0.25			
Amount Removed	Tons / Year	38,268			
		<b>Current Dollars</b>		<b>Constant Dollars</b>	
Levelized Cost of Power		<b>Factor</b>	<b>Mills/kWh</b>	<b>Factor</b>	<b>Mills/kWh</b>
Capital Charge		0.1604	7.53	0.124	5.82
Fixed O & M Cost		1.293	1.00	1.000	0.78
Variable Operating Cost		1.293	2.29	1.000	1.77
Total Cost			10.82		8.37
Levelized Cost - SO <sub>2</sub> Basis		<b>Factor</b>	<b>\$/ton Removed</b>	<b>Factor</b>	<b>\$/ton Removed</b>
Capital Charge		0.1604	336.14	0.124	259.86
Fixed O & M Cost		1.293	44.80	1.000	34.65
Variable Operating Cost		1.293	102.11	1.000	78.97
Total Cost			483.06		373.48
Levelized Cost - SO <sub>2</sub> + NoX Basis		<b>Factor</b>	<b>\$/ton Removed</b>	<b>Factor</b>	<b>\$/ton Removed</b>
Capital Charge		0.1604	0.00	0.124	0.00
Fixed O & M Cost		1.293	0.00	1.000	0.00
Variable Operating Cost		1.293	0.00	1.000	0.00
Total Cost			0.00		0.00

Table 7.1-7 summarizes the costs for each technology evaluated. In the table, the base case is presented first, with the other technologies presented in ascending order of ranking, from lowest cost to highest, based on total lifecycle costs in current mills/kWh. As shown in the table, the base case, i.e., the limestone forced oxidation technology with the wallboard gypsum byproduct, has a levelized cost of power of 10.82 mills per kilowatt hour. The limestone forced oxidation technology with the wallboard gypsum byproduct is therefore the fourth least cost option out of the nine technologies evaluated. The least cost alternative is shown to be the CT 121 option, with a value of 10.06 mills per kilowatt hour.

The summary cost results for each alternative evaluated are provided in Appendix C of this report. Total Capital Requirements, Total Fixed and Variable O&M Costs and Total Levelized Costs analyses are presented for each FGD system.



**TABLE 7.1-7  
FGD Technology Cost Comparison**

TECHNOLOGY	CAPITAL COSTS		OPERATING & MAINTENANCE COSTS						SO <sub>2</sub> REMOVED Tons/yr	LEVELIZED COST OF POWER		LEVELIZED COST - SO <sub>2</sub> BASIS			
	Total Process Capital \$ x 1,000	Total Capital Requirement \$ / KW	Fixed \$ x 1,000	Consumables \$ x 1,000	Electric Power \$ x 1,000	By-products \$ x 1,000	Waste Disposal \$ x 1,000	Total Fixed & Variable \$ x 1,000		Current Mills/ kWh	Constant Mills/ kWh	Current Mills/ kWh	Constant Mills/ kWh		
S-H-U w/WALLBOARD GYPSUM	45,796	152.7	80,197	267.3	1,326	1,093	2,300	(371)	0	4,348	38,268	10.82	8.37	483.06	373.48
CHIYODA THOROUGHbred 121	36,433	121.4	68,917	229.7	1,302	980	1,372	0	1,088	4,742	38,268	10.06	7.78	449.08	347.22
PURE AIR	38,813	129.4	71,998	240.0	1,334	1,019	1,502	0	1,113	4,969	38,268	10.52	8.14	469.66	363.13
SAARBERG-HOLTER THROWAWAY GYPSUM	38,308	127.7	71,565	238.6	1,328	1,064	1,761	0	1,100	5,253	38,268	10.70	8.27	477.44	369.15
LIMESTONE FORCED OXIDATION, THROWAWAY GYPSUM	38,876	129.6	72,640	242.1	1,335	1,067	2,272	0	1,146	5,820	38,268	11.23	8.68	501.10	387.45
DIBASIC ACID ENHANCED LIMESTONE	38,549	128.5	72,318	241.1	1,331	1,206	2,258	0	1,146	5,940	38,268	11.29	8.73	503.81	389.55
INHIBITED OXIDATION LIMESTONE	42,476	141.6	77,295	257.6	1,384	1,075	1,930	0	1,767	6,156	38,268	11.92	9.21	531.98	411.33
MAGNESIUM ENHANCED LIME	39,254	130.8	73,993	246.6	1,340	2,270	1,921	0	1,623	7,154	38,268	12.36	9.56	551.86	426.71
LIME SPRAY DRYER	41,562	138.5	77,464	258.2	1,372	3,858	1,005	0	1,869	8,104	38,268	13.41	10.37	598.52	462.78

Plant Size (Mw): 300  
 Capacity Factor: 65%  
 FGD Efficiency: 95%  
 Plant Life (yrs): 15  
 Sulfur in Coal: 3.2%

Plant Heat Rate (Btu/kWh): 9,401

## **Advanced Technology Comparisons**

The comparison of the SHU FGD process against advanced technology concepts such as coal gasification, fluidized bed combustion, fuel cells, or other concepts cannot be addressed in detail due to the complexity of the assumptions and variables that would need to be addressed in such a comparison.

Some competing processes landfill their solid waste. The throw-away sodium-based systems, such as the soda ash and dual-alkali, are based on expensive soda ash reagent and generate large quantities of sludge for disposal. Ever increasing landfill disposal costs and public resistance to new landfill siting will make expanded use of these processes less likely.

The SHU process can also be compared on an equivalent basis, since the process can be configured to produce gypsum intended for landfill disposal. The calcium sulfite waste produced by conventional FGD processes is significantly inferior to the SHU landfill grade gypsum. Calcium sulfite waste is mechanically unstable and must either be ponded or mixed with dry fly ash and lime for landfill disposal. If calcium sulfite is ponded, three to five times the land area needed for gypsum disposal is required. For example, during a 30-year life of two 500 MW units firing 2.5 percent sulfur coal, disposal of ponded calcium sulfite would require 400 to 700 acres of land, depending on pond depth. Only 130 acres would be required for gypsum disposal (by stacking). If calcium sulfite were landfilled along with fly ash, space requirements would be greater than those for stacked gypsum. In addition, operation of a stabilized sulfite sludge landfill is more complex and costly than for gypsum stacking. Landfilling calcium sulfite would require thickeners, vacuum filters, dry ash handling equipment, pug mills for sludge/lime/ fly ash mixing to fixate the sludge mixture, truck transportation to the landfill, and placement and compaction at the landfill site. Fly ash would no longer be available for sale if it were required for mixing with the calcium sulfite material.

The formic acid buffering capacity of the SHU process, along with the cocurrent/countercurrent absorber results in capital savings due the need for smaller equipment. Typical savings are summarized in table 7.1-8.

Compared to its competition, operating economics are also excellent. This is due to:

- The operational flexibility that increase limestone utilization and reduce auxiliary power requirements, therefore leaving more power available for sale;
- The revenue from marketing the high quality gypsum byproduct;
- Reduced water consumption and disposal waste
- Improved system economy because of the greater dispatch and ramping flexibility; and finally,
- Lower maintenance requirements.

**TABLE 7.1-8**

**SHU PROCESS CAPITAL SAVINGS FROM REDUCED SIZE EQUIPMENT  
COMPARED TO COMPETING PROCESSES**

<b>Item</b>	<b>Approximate Size Ratio</b>	<b>Approximate Capital Savings</b>
Recycle Pumps	25 % Smaller Volume	15 %
Tower Mills	Up to 50 % Smaller	25 % to 30 %
Oxidation blowers	25 % Smaller Volume	15 %
Induced Draft or Booster Fans	15 % Lower Pressure Drop	10 %

As a result of the FGD evaluations conducted by NYSEG at Milliken Station, NYSEG found the SHU process to be one of the most flexible, reliable, and cost-competitive FGD processes available. Moreover, NYSEG believes that successful demonstration of the innovative design changes will significantly reduce the cost of the SHU process and further enhance its attractiveness for retrofit.

**COMMERCIALIZATION PLANS**

The normal path to commercialization for a product of a technology typically requires up to 20 years; however, commercializing the SHU process will be more rapid.

The steps for complete commercialization of an FGD process are typically:

- Ideas to resolve a problem or reduce a cost
- Proof-of-concept testing
- Technology development (bench scale) to resolve technical issues/reach technical goals
- Engineering development (bench scale and scale-up) to reach cost, performance, and life goals
- Demonstration of fabrication/manufacturing
- Demonstration at a scale large enough to establish user confidence
- Prototype testing
- Early commercial implementation
- Mature commercial application and second generation improvements.

Each of the early stages are accompanied by increasingly complex studies, model development, and designs to determine whether to proceed to the next stage. The cost of each stage is greater than the previous one, such that at later stages, the large capital requirements lead to significant concerns about the validity of scale-up factors.

These later stages are also accompanied by market studies, promotions, efforts raising financial backing, and overcoming institutional hurdles.

The approach to commercialization of the SHU FGD process requires a different path to commercialization than normally associated with a new product, as outlined above. As a result, the difficulties and schedule to commercialize are greatly reduced. Early commercial introduction in the American power market is possible because the SHU process is already in the commercialization step in Europe and Asia. The focus of the MCCTD project, then is on integrating U.S.-manufactured equipment, integrating U.S. engineering, integrating U.S. fuels, and on operating the equipment effectively in accord with U.S. practices to minimize costs while achieving the high sulfur removal goals promised by the process. These latter steps are possible since the European experience eliminates the need for extensive equipment development. The Milliken retrofit demonstration is at a size and in an environment that provides confidence and verifies the economics of the approach for the U.S. power industry.

The individual equipment components used in the process are available from U.S. manufacturers at the scale required to be used in a commercial installation. This condition has the effect of reducing the steps necessary in commercializing the technology. Thus, the steps required for the commercialization of the SHU process in the U.S. are

- Demonstration at a scale large enough to establish user confidence in a U.S. utility environment
- Prototype testing at a large (300 MW) operating utility power plant
- Establishing U.S. utility confidence in the technical and economic worth of the approach.

All of these steps have been demonstrated by the MCCTD project. Following the demonstration, the final step becomes possible

- Widespread commercial application

Several critical factors normally affecting commercialization of a particular product or process are not applicable to the SHU process. For example, financing to develop the equipment and manufacturing of the equipment need not be addressed, since the process engineering and major equipment have been previously developed.

Commercialization of the SHU process was initiated during the demonstration and has been ongoing throughout the project. By 1999 it will be fully implemented. While Saarber-Hölter Umwelttechnik GmbH, a German company, owns the SHU process license and supplied the basic process engineering, a majority of detailed design services and all equipment for the project were supplied by U.S. companies. A U.S. company, SHN Technologies, has been formed between NYSEG and SHU to market

and provide the process in the U.S. for future SHU projects. This will aid in the development of the U.S. manufacturing base that will be supplying the process to the U.S. power industry.

It is SHU's intent that the Milliken station, as the first SHU plant in the U.S., serve as a "showcase" installation for site visits of potential clients. The high efficiency and flexibility of the process as demonstrated at Milliken should dramatically increase the attractiveness of the technology to U.S. utilities. Data collected during the demonstration has validated the applicability of the technology on a wider range of coals and sulfur levels than previously demonstrated in Europe. The demonstration in conjunction with the other advance concepts included in the project are expected to increase interest in the process above that generated by demonstration of the process by itself. SHU experience at the Model Power Station Völklingen with the FGD unit inside the cooling tower along with fluidized bed combustors for coal tailings, has generated a tremendous increase in interest in the technology as evidenced by the tens of thousands of visitors to the plant. SHU feels that SHU's rise to the second leading supplier of FGD equipment in Germany can be traced in large measure to the successful demonstration at Völklingen. SHU anticipates a similar response to a successful demonstration at Milliken Station.

the Stebbins tile. The tiles are also well suited to retrofit applications, where site space and construction access is usually at a premium. Since the absorber is constructed from relatively small tiles, access during construction is less of a construction site burden.

In addition, as a result of dissatisfaction with conventional lining systems, some utilities have begun to use an alloy wallpaper or cladding lining system whereby very thin gage sheets of high nickel alloy (e.g. Hastelloy C-276) are welded to the carbon steel substrate. The suitability of such construction in highly abrasive scrubber locations has not been fully demonstrated. More conservative designs use solid alloy construction. However, especially for applications with high chloride in concentrations, this construction requires a high capital cost premium and does not provide corrosion/erosion protection comparable to Stebbins tile.

Table 7.2-3 summarizes and compares the capital costs of the various materials most frequently used in absorber recirculation tank construction with the Stebbins tile absorber design. The analysis is based on a normalized design configuration for a 300 MW commercial plant.

**Table 7.2-3  
FGD Absorber Capital Cost Comparison**

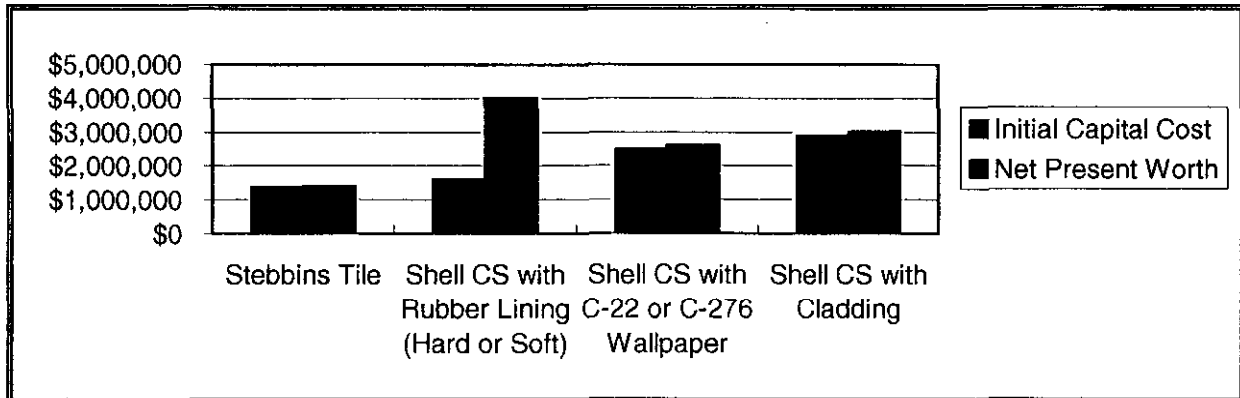
Material**	1997		
	Procurement/ Fabrication	Erection	Total
Stebbins Tile	\$1,374,000	Included	\$1,374,000
Shell CS with Rubber Lining (Hard or Soft)	\$1,603,000	Included	\$1,603,000
Shell CS with C-22 or C-276 Wallpaper	\$2,519,000	Included	\$2,519,000
Shell CS with Cladding	\$2,919,750	Included	\$2,919,750

\* Lining/coating cost varies based on surface area and site location.  
 \*\* Lining material cost includes field installation.

Maintenance costs for the Stebbins tile lined absorber is minimal. Maintenance costs consist primarily of inspections every two years to determine absorber condition, and limited repointing incurred at five year intervals. In contrast, a rubber-lined carbon steel absorber will require full liner replacement at eight year intervals. The alloy wallpaper and clad absorbers generally have a service life of 25 years, and equally low maintenance costs.

Figure 7.2-1 provides a comparison of capital costs and net present worth of the four absorber materials evaluated as part of this study. The costs are based on a 15 year plant life for each material.

**Figure 7.2-1  
Absorber Materials Cost Comparison**



The values presented in Table 7.2-3 and Figure 7.2-1 serve to highlight the competitive costs of the Stebbins tile absorber construction approach, when compared to the costs of other frequently used absorber materials. It is clear that, with its competitive capital cost and intrinsically low maintenance cost component, the lifecycle costs of the Stebbins absorber module represent a cost effective option for FGD absorber construction.

### COMMERCIALIZATION PLANS

The normal path to commercialization for a product of this type typically requires up to 20 years; however, commercializing the Stebbins Tile Absorber will be more rapid. The steps for complete commercialization of an FGD Absorber Construction System are typically:

- Ideas to resolve a problem or reduce a cost
- Proof-of- concept testing
- Technology development (bench scale) to resolve technical issues/reach technical goals
- Engineering development (bench scale and scale-up) to reach cost, performance, and life goals
- Demonstration of fabrication/manufacturing
- Demonstration at a scale large enough to establish user confidence
- Prototype testing
- Early commercial implementation
- Mature commercial application and second generation improvements.

Each of the early stages are accompanied by increasingly complex studies, model development, and designs to determine whether to proceed to the next stage. The cost

of each stage is greater than the previous one, such that at later stages, the large capital requirements lead to significant concerns about the validity of scale-up factors. These later stages are also accompanied by market studies, promotions, efforts raising financial backing, and overcoming institutional hurdles.

The approach to commercialization of the Stebbins Tile Absorber Construction requires a different path to commercialization than normally associated with a new product, as outlined above. As a result, the difficulties and schedule to commercialize are greatly reduced. Several critical factors normally affecting commercialization of a particular product or process are not applicable to the Stebbins Tile Reinforced Concrete Absorber. For example, financing to develop the technology and manufacturing of the technology need not be addressed, since the process engineering and major components and construction methods have been previously developed. Early commercial introduction in the U.S. FGD absorber market is also possible because The Stebbins Tile Reinforced concrete construction system has already been successfully commercialized. The Stebbins process has fully proven itself in similar applications in the pulp and paper, chemical and mining industries. On an annual basis, Stebbins Engineering and Manufacturing Company constructs approximately 10-15 large (\$2-\$10 million per) installations utilizing the proposed construction methods and materials of construction. This construction system is familiar to the utility industry through its use in auxiliary scrubber related power plant tankage. The tile and grout portion of the Stebbins system has proven its corrosion/abrasion resistance as a replacement for failed liners in several FGD absorber and flue gas duct applications. Additionally, this technology had been used in conjunction with the M.W. Kellogg Horizontal Weir Absorber process design since 1982 at the Big Rivers Electric D.B. Wilson station.

Based on this, the steps required for the commercialization of the Stebbins Tile Reinforced Concrete Absorber construction in the U.S. are:

- Demonstration at a scale large enough to establish user confidence in the available savings in plot space, construction access and construction costs.
- Prototype testing at a large (300 MW) operating utility power plant.
- Further establishing U.S. utility confidence in the technical and economic worth of the approach.

All of the above are demonstrated by the Milliken project. Following that demonstration, the final step becomes possible.

- Widespread commercial application.

Commercialization in the U.S. will only be advanced by the Milliken demonstration. Sales efforts will be ongoing throughout the project.



Stebbins is the only North American corrosion resistant lining company with a field crew of brick masons of over 140. In addition to being capable of installing Stebbins' brick/tile lining systems, the majority of Stebbins' field crew are capable superintendents. As superintendents, they are responsible for managing the entire labor force for a project. Furthermore, due to its affiliation with the international Mason Contractor's Association, Stebbins has available from local union halls throughout North America approximately three times the number of brick masons shown above, all of whom are "Stebbins qualified". To ensure quality, however, Stebbins requires masons hired from union halls to work with a Stebbins supervisory mason.

Stebbins has proven project management capability. For projects in the northeastern United States, Stebbins' project management personnel are supplied from their corporate headquarters in Watertown, New York. Stebbins and subsidiaries have, in North America, several projects in the million dollar plus range at any given time.

Stebbins lining experience dates from 1884 beginning with the complete design and installation of pulp and paper mills. Their corrosion resistant lining experience and capabilities have grown considerably over their history due to diversification from the pulp and paper industry into the mining, chemical and power industries. Their client list in the chemical and mining industry includes such major companies as INCO, American Barrick, DuPont, Oxychem and Kerr McGee. The continual growth of their client list has been due to their premium quality lining installation, superior service capabilities and their excellent reputation for standing behind the work they complete. With over 100 years of experience in corrosion resistant lining, engineering and installation in various industries, Stebbins is a leading company in this field of work. Their full service turnkey approach to projects has enabled them to satisfy thousands of clients and has allowed them continual growth over the years.

Stebbins' excellent reputation has been built on quality installations, superior service capabilities and the commitment to stand behind their work. Unlike standard warranties which only warrant that the materials are supplied to a certain specification and the installation of materials is completed according to the manufacturer's recommendations, Stebbins takes full responsibility that the lining specification is appropriate for the service conditions of the particular vessel. They term this type of warranty a "use warranty" because they commit that the lining is suited for the operating/design conditions of the specific vessel. They are able to supply such a comprehensive warranty because they perform the lining design, supply the material and the installation. This avoids a split responsibility between the material supplier and the installation contractor.

Commercialization of the Stebbins Tile Reinforced Concrete Absorber Construction was initiated during the demonstration and has been ongoing throughout the project. It should be fully commercialized by 1999.

## **7.3 HEAT PIPE AIR HEATER SYSTEM**

### **MARKET ANALYSIS**

The Q-Pipe® Air Preheater, QAP-157, Vertical Flow, Model 303.8-408-36DV, provided by ABB Air Pre-Heater for use on the Milliken Clean Coal Demonstration project, is an innovative replacement option for the Ljungstrom® air heater. The air heater provides energy savings by eliminating air leakage across the air heater and by allowing lower average exit gas temperatures. It has been estimated that for every 35 °F drop in flue gas temperature, plant efficiency increases by approximately one percent; thus there is significant incentive to install a heat pipe air heater which allows flue gas temperature reduction by maintaining uniform temperatures.

Since FGD retrofits consume auxiliary power, capacity is lost during retrofit. The heat pipe air heater retrofit at Milliken Station, along with other performance enhancing changes, were intended to restore much of the lost power, and improve overall performance. With improved energy conservation, fewer tons of coal need to be burned to produce the electric power demanded. This reduces the amount of pollutants in need of control, and also reduces the amount of greenhouse gases that are produced.

The direct benefit of the heat pipe air heater technology is the reduction in air leakage across the air heater from 16% of the entering air to zero. This represents an auxiliary power savings of 452 BHP (based on Milliken Station flow rates for one unit). In addition, a thermal efficiency improvement of approximately 0.5% can be realized due to a 20° F (approximately) lower uncorrected gas exit temperature. With the integration of an advanced technology corrosion monitoring system (CAPCIS), the flue gas exit temperature may be further reduced to 25° F (from 280° F to 255° F) which would result in an overall boiler efficiency improvement of approximately 0.6%.

The heat pipe modules have no moving parts and are constructed with carbon steel and alloy finned tubes which have been evacuated, partly filled with heat transfer fluid and permanently sealed at both ends. One end of each tube is exposed to the hot boiler flue gas; the other end is exposed to either primary or secondary combustion air. Heat absorbed from the flue gas vaporizes the heat transfer fluid within a tube. The vaporized fluid travels up the tube, transferring heat to the cooler combustion air side of the unit. There the heat transfer fluid condenses and flows back to the flue gas side. The process continues as long as there is a temperature differential between the combustion air and the flue gas.

The heat pipe tubes are installed at a slight angle with the flue gas section lower than the combustion air section in order to provide a gravity assist to the returning, condensed heat transfer fluid from the combustion air side. A patented internal capillary wick, formed by a circumferentially spiraled groove, enhances the heat transfer process in two ways. In the flue gas section, the wick distributes the heat transfer liquid around the entire inner circumference, providing a fully wetted surface for maximum heat transfer. In the

combustion air section the wick provides a roughened surface to achieve higher heat coefficients. The heat pipes are isothermal, providing even heat distribution with no hot or cold spots. Cold end corrosion risk is reduced because exit temperatures are uniform.

## **APPLICABILITY OF THE TECHNOLOGY**

The heat pipe air heater technology can be applied to replacement of existing regenerative and tubular air heaters in sizes equivalent to Milliken's as well as smaller sizes and sizes up to twice Milliken's where leakage improvement and efficiency improvement are desired. A primary target will be in retrofit applications where reduced gas flow will allow downsizing of new downstream emission control equipment. The size of the heat pipe air heater demonstrated at Milliken can be used on much larger stations if the air preheat arrangement is sub-divided. A split back-pass 400 MW boiler, for example, could be retrofitted with two heat pipe air heater modules of the demonstration size. It is also expected that the market application will include the heat pipe air heater both with and without corrosion monitoring features. The heat pipe air heater also has an expected market application in new facilities. The advantages are the same as in retrofit applications, and the benefits may be greater where the original plant design includes the heat pipe air heater.

## **MARKET SIZE**

This type of air heater potentially has a wide market appeal. A fully detailed analysis of the potential market for heat pipe air heaters is provided in Volume I of the *Public Design Report*. The results of this analysis are summarized in table 7.3-1. This technology is suited to any power generator, either utility or industrial, in need of reduction of leakage, heat rate improvement, and wide latitude in range of operating temperatures. Its use is suited to many applications beyond simply scrubber upgrades. The potential retrofit market is only limited to fossil units currently in service which will not be retired before 2030. The heat pipe air heater system is also applicable to all new coal-fired power plants.

The market penetration for the heat pipe air heater technology was assessed in a similar fashion to that of the SHU process. However, since the air heater is not limited to plants with needs for scrubbers, the potential market is much larger. Although the heat pipe air heater can be used in industrial boilers as well as electric utility applications, the study limited the market penetration analysis strictly to utility applications. Consideration of improved industrial acceptance due to this larger retrofit would serve to enhance the potential benefits to the U.S. Table 7.3-1 shows the share of the utility air heater market that the heat pipe air heater technology is estimated to capture. A projection of 35 years, from 1996 to 2030, is presented in five year increments. Each year's fractional shares depends on the previous year's fractional shares. This means that an initial market share for the technology is required and must be assumed to stimulate a market. A 1.5 percent share was assumed. This is considered realistic in that it shows that an outside force, such as the Milliken project or an initial investment, is needed before the product

becomes accepted. Based on this analysis, the heat pipe air heater technology has the potential of increasing its share of the utility air heater market to approximately 25 percent by the year 2030. The projected heat pipe air heater market share for retrofits in the U.S. through the year 2030 totals 4805 MW. The projected heat pipe air heater market share in the U.S. for new power plants through 2030 totals 109,578 MW.

**TABLE 7.3-1  
ESTIMATED MARKET PENETRATION FOR HEAT PIPE AIR HEATER SYSTEM**

Year	Five Year Avg. share
1996-2000	0.020
2001-2005	0.032
2006-2010	0.050
2011-2015	0.077
2016-2020	0.117
2021-2025	0.172
2026-2030	0.245

### **MARKET BARRIERS**

The key features of the heat pipe air heater system which make it attractive to potential utility customers are:

- Improvement in boiler thermal efficiency over a regenerative air heater with the same flue gas exit temperature. Further improvement with lower gas exit temperatures.
- Zero leakage from air side to flue gas side.
- Similar heat recovery capabilities as a regenerative air heater for the same space requirements.
- Potential for increased heat transfer, reduced exit gas temperature, and increased boiler efficiency due to CAPCIS corrosion monitoring system.
- Easily replaceable tubes or modules.

While both the heat pipe and the CAPCIS probe have been used on boilers firing high sulfur coal prior to the Milliken demonstration, the use of the combination of these technologies had not been commercially demonstrated prior to the Milliken project, resulting in a significant barrier to market penetration. The successful demonstration of these features while avoiding significant operating and maintenance problems should help in overcoming this barrier and encourage the widespread commercialization of heat pipe air heaters. However, failure of the high efficiency air heater system could result in plant shutdown or low load operation. Factors which could cause air heater system unavailability include:

- Corrosion of tubes or plates due to SO<sub>3</sub> condensation.

- Inability to achieve design heat transfer rates due to unanticipated fouling and/or inability to clean the heat transfer surfaces.
- Inability to handle the required throughput of flue gas due to plugging with resultant high pressure drop across the unit.

The significant occurrence of failures of this type could discourage the widespread application of these technologies.

## **ECONOMIC COMPARISONS WITH COMPETING TECHNOLOGIES**

There are two air heater technologies that compete with the heat pipe air heater. These are the rotary regenerative air heater and the tubular recuperative air heater. The rotary regenerative air heater consists of a large rotating wheel (rotor) of regenerative heat transfer surface which continuously turns through the gas and air streams. The main disadvantage of this type of air heater is the relatively high air leakage associated with this design and the even metal temperatures which must be maintained to minimize corrosion.

The tubular recuperative type air heater consists of a shell and tube multiple pass heat exchanger where the combustion air flows over the tubes and flue gas flows inside the tubes. The main disadvantages of this type of air heater are low metal temperatures in the cold end resulting in increased corrosion and fouling problems and the increased physical size required for the higher heat recovery sizes.

The competitive advantages of the heat pipe air heater system, compared to the Ljungstrom® and tubular recuperative type air heaters are discussed below.

With the heat pipe air heater system there is no leakage between the combustion air and the flue gas. Ljungstrom® type air heaters have radial and axial seals that are designed to reduce the leakage from the combustion air side of the preheater to the flue gas side. As the heat transfer elements (rotor) turn, air will leak into the gas in three ways: leakage into the gas chamber resulting from entrainment in the rotor passages, leakage at the periphery of the rotor through the clearance space between the rotor and the housing and then into the gas passage and leakage across the radial seals into the gas passage. The leakage reduces the flue gas temperature and causes corrosion and fouling of the air heater, in areas of flue gas condensation. The leakage increases forced and induced draft fan loads, reduces boiler thermal efficiency (since less heat is transferred to the combustion air) and increases maintenance on the air heater through the annual replacement of seals.

The heat pipe air heater technology improves heat rate and reliability due to less potential for corrosion. Conventional recuperative tube air heaters are designed with the flue gas flowing through the tubes, in a crossflow arrangement. The crossflow arrangement results in poor gas distribution and a high temperature differential between

the flue gas and the combustion air at the air inlet and the gas outlet area. Because the distribution is poor, and the difference in temperature is high, the flue gas condenses and tube corrosion occurs. Ljungstrom® type air heaters experience problems because of their rotating nature and the resulting high temperature differential between the metal elements and the flue gas. As the air heater elements rotate between hot flue gas and cold combustion air, the metal baskets are heated and cooled. The metal that is cooled in the combustion air is instantly subjected to hot fly ash and sulfur oxides on the flue gas side. This causes the sulfur oxides to condense and corrode the baskets and seals, while the fly ash agglomerates and fouls the air heater passages. Heat pipe air heaters, do not suffer from either high temperature differentials or poor gas distribution. The heat pipe is designed with the flue gas flow over the tubes, which enhances gas mixing and provides a more uniform temperature profile than either the tubular or regenerative air heaters. The heat pipe operates on counterflow principles and the heat pipes are isothermal. The result is that the air and gas stream temperatures along a row of heat pipes are virtually uniform, with a temperature differential of close to zero. A much smaller percentage of the total tube bundle and the center tube sheet is exposed to corrosive conditions. Therefore, flue gas condensation is reduced and corrosion and fly ash agglomeration (and fouling) are greatly reduced. The heat pipe air heater installed at Milliken used the CAPCIS corrosion detection system. The CAPCIS system is based on a combination of electrochemical impedance measurements (EIM), electrochemical potential noise (EPN) and electrochemical current noise (ECN). This combination of measurements is highly sensitive and reacts rapidly to changes in the rate of corrosion. The CAPCIS system is used to control the air heater gas bypass dampers, allowing the heat pipe air heater to be operated at the minimum flue gas outlet temperature consistent with acceptable corrosion rates as indicated by the CAPCIS system.

The tube pitch and tube pattern of a heat pipe air heater can be designed to reduce fouling and cleaning requirements. The pitch and pattern set the gas velocity to establish a self-cleaning scouring action, and to assure that the soot blowing is thorough. The fin density design sets the expected wet fouling zone and fin biasing is used to increase the heat recovery and move the minimum metal temperature row by row. Fin thickness and tube wall thickness influence the effects of corrosion. Tube and fin materials set the lower exit gas temperature. The modular construction and the provision for the replacement of individual pipes allows for heat pipe optimization and reconfiguration. Therefore, if corrosion occurs, or occurs at a greater rate than is acceptable, the characteristics of the heat pipe allow it to be modified easily. Conversely, if greater heat transfer were required from the heat pipe, additional tubes, or tubes with more or larger fins could be installed.

The heat pipe air heater has no moving parts. There is no drive assembly or rotating elements inside the heat exchanger. There are no shafts, bearings, seals, sector plates, drive motors, speed reducers/gear boxes, cooling fluids, lubricants or plate filled baskets to wear out or maintain, such as are found in the Ljungstrom® regenerative air heaters. The heat pipe requires no energy to operate, other than the sootblowers. The heat pipe

heat exchanger requires no maintenance, other than an annual inspection. If corroded tubes are found, they can be replaced, however a properly designed heat pipe, that utilizes the proper materials and fin and tube designs, should not suffer from corroded tubes.

### **Economic Comparison**

Although the thermal performance of the new heat pipe air heaters was not better than the replaced Ljungstrom® units, the use of the heat pipes provided considerable improvement in fan power requirements. This is shown by direct comparison of the Unit 1 and 2 operating results for similar conditions of boiler excess air and gross load. Such a comparison is justified since Milliken Units 1 and 2 are identical except for the use of Ljungstrom® air heaters with hot primary air fans in Unit 1 and heat pipe air heaters with cold primary air fans in Unit 2. At 100 MW and 150 MW gross load, the Unit 2 combined power requirements for the primary air, secondary air, and induced draft (ID) fans, averaged 0.67MW (900hp) and 0.78MW (1050 hp) less than for Unit 1, respectively.

Most of the power savings can be attributed to the lower combustion air and flue gas flows for the Unit 2 boiler due to the zero air leak operation of the heat pipe air heaters. The differences represent considerable power cost savings for the zero leak heat pipe system. Assuming incremental costs of 2.3~/kW and a 65% plant capacity factor, the 25 year life cycle power cost saving is estimated at \$2.5 5MM. Actual power cost savings are likely to be greater since these results have not considered power reductions for the electrostatic precipitator and the FGD system with optimized pumping (i.e., headers removed from service to accommodate reduced flue gas flow).

Following in Table 7.3-2 is an economic comparison of the heat pipe technology with competing regenerative and recuperative preheater alternatives. The economic data for the Ljungstrom regenerative air heater, the recuperative plate air heater and the tube air heater has been furnished by ABB Preheater, Inc. It should be noted that ABB is not currently actively marketing the heat pipe technology. At present, ABB believes that the Ljungstrom air heater represents a reliable technical solution, is competitive from an economic vantage, and environmental concerns associated with the use of naphthalene in the welding process for the heat pipe can be avoided. In addition, it is possible to compensate for intrinsic air loss by increasing the air flow through the air heater.

**Table 7.3-2  
Heat Pipe/Air Heater Cost Comparison  
(\$ X 10<sup>6</sup>)**

	Heat Pipe	Ljungstrom Regenerative Air Heater	Apex Recuperative Plate Air Heater	Recuperative Tube Air Heater
Equipment Cost	\$2.10	\$ .750	\$1.05	\$1.10
Installation Cost	\$1.00	½ of heat pipe	Similar to heat pipe	
Annual Operating Cost (BHP @ .04/kW, @ 65% Capacity)	\$.122	\$.122	\$.138	\$.209
Annual Maintenance Cost	Base	¾ of heat pipe	Similar to heat pipe	

Annual operating costs are based on an analysis of electrical requirements associated with the heat pipe and air heater equipment. The analysis is presented below in Table 7.3-3.



**7.3-3  
Heat Pipe/Air Heater Comparison  
Total BHP**

Alternative	Primary Air					Secondary Air					Flue Gas										
	head inwc	flow, #/hr	Temp, °F	density, #/ft <sup>3</sup>	Flow, ACFM	Air HP	head inwc	flow, #/hr	Temp, °F	density, #/ft <sup>3</sup>	Flow, ACFM	Air HP	head inwc	flow, #/hr	Temp, °F	density, #/ft <sup>3</sup>	Flow, ACFM	Air HP	total Air HP	Fan Eff	Total BHP
Ljungstrom	2.8	125,000	68	0.07528	27674	12	2.8	1205000	68	0.07528	266782	117	4.7	1580000	270	0.0552	477053	352	481	0.9	535
Heat Pipe	3.6	125,000	68	0.07528	27674	16	5.35	1125000	68	0.07528	249070	209	3.65	1500000	270	0.0552	452899	260	484	0.9	538
Plate Type recuperative	4.5	125,000	68	0.07528	27674	20	4.5	1125000	68	0.07528	249070	176	4.9	1500000	270	0.0552	452899	348	544	0.9	604
Tubular Type Recuperative	7.1	125,000	68	0.07528	27674	31	7.1	1125000	68	0.07528	249070	276	7.3	1500000	270	0.0552	452899	519	828	0.9	920

## **COMMERCIALIZATION PLANS**

Prior to the Milliken project there were three milestones essential to the commercialization of the heat pipe air heater system, consisting of the air heater and CAPCIS corrosion monitor controls. These milestones were:

- Issuance of a purchase order for the air heaters at the Milliken demonstration facility
- Completion of demonstration of the success of the air heater technology for the demonstration project
- Completion of the development of a strategic marketing plan.

It was expected that the issuance of the purchase order itself would promote acceptance and therefore spawn commercialization of this technology. Demonstration of the technology was scheduled for completion within one year of plant startup. Development of a strategic marketing plan for the air heaters product was expected to parallel the demonstration and be completed within a year after the conclusion of the demonstration.

The infrastructure (ABB Air Pre-Heater) for commercialization of heat pipe air heaters was already in place prior to the demonstration due to the smaller size units which had been commercialized for other applications of the heat pipe technology. The scale-up to the demonstration size air heater is not significantly different, from a manufacturing viewpoint, than the present commercial sizes because of the modular construction concept and similarity of individual parts (e.g., the tube diameter for the smaller scale version is the same as for the larger scale). The tube materials, quantity, lengths and fin design will change instead.

Some features which are desirable for the commercialization of the heat pipe air heater which were not demonstrated by the Milliken project are:

- Operation with higher sulfur content coals in a pulverized coal power plant.
- Anticipated commercial sizes will include the size used for the Milliken demonstration and sizes ranging from 25% to 200% of the Milliken size.

The design of the heat pipe heat exchanger is individually tailored to meet the required thermal performance. The tube pitch and pattern, the fin density and fin biasing and the fin thickness and tube wall thickness can all be changed for each installation. The modular construction and the type of material used for the tubes and fins are based on the type of application and the type of fuel that is burned. The Milliken demonstration did not attempt to evaluate all of the various alternatives of the heat pipe air heater construction. It determined the most efficient design for a tangentially fired boiler firing high sulfur coal. Utilities with cyclone and stoker boilers will have to develop the correct design for their specific applications. The use of the CAPCIS probe was specific for the Milliken application also. The configuration of the duct work, the type and amount of thermal insulation and the type and location of the particulate control systems will

determine the number and locations of probes and, consequently the rate of corrosion and the resulting thermal efficiency savings that can be achieved.

## **7.4 PLANT ECONOMIC OPTIMIZATION ADVISOR (PEOA™).**

The purpose of this section is to describe current and future activities related to the promotion, marketing, and sales (commercialization) of the Total Optimization Project Advizor (TOPAZ™). This product line is currently licensed to DHR under a NYSEG License Agreement dated February 19, 1997.

TOPAZ™ is a software product that has evolved from the development of the Fossil Thermal Performance Advisor (FTPA™) and Plant Economic Optimization Advisor (PEOA™). TOPAZ™ includes the very best features of FTPA™ and PEOA™, and has been packaged into stand alone modules with options to allow the marketplace greater flexibility. The principal modules of TOPAZ™ are:

- Process Monitor
- Process Optimizer
- Process Advisor
- Editor

Each of these modules is described below.

Previous efforts to market TOPAZ™ have focused on the benefits derived from FTPA™, primarily heat rate efficiency. Because of the current industry emphasis on emissions control, and due to new regulations such as the Clean Air Act, the emissions monitoring and advisory features of PEOA™ are also in high demand.

The primary intent of the PEOA™ Commercialization Plan is to help focus efforts on leveraging the emissions monitoring and control features of TOPAZ™, and to establish mutually agreeable sales and marketing goals and successes. This will be accomplished through several means including implementation of a vigorous promotional advertising campaign, combined with complementary presentations at various conferences and potential client facilities. In addition, DHR intends to team with strategic alliances/partners such as DCS manufacturers to promote TOPAZ™.

The success of this product will be monitored at least quarterly and DHR will redirect its efforts as appropriate. Subsequent sections of this plan provide additional details concerning DHR's current commercialization goals and objectives, and plans for implementation of these goals and objectives.

### **MARKET ANALYSIS**

#### **Background**

The fossil utility industry is becoming more competitive due to new regulations, such as the Clean Air Act, and increased competition from deregulation. Also, some utilities are

beginning to evaluate each plant as a separate cost center responsible for its own bottom line. These developments have encouraged power plant management to search for new ways to monitor, analyze and optimize total plant performance.

A key aspect of the total plant optimization problem is the impact that plant operations personnel can have on overall plant efficiency. Historically, plant systems have been operated on a system-by-system basis, and operators are tasked primarily with keeping the plant on-line. Though many units have installed on-line performance monitoring systems to help improve efficiency, operators are often relatively ill-informed of the impact their actions can have on overall economic performance. Additionally, the inter-relationships between plant sub-systems are rarely incorporated into operational strategies. In order to truly optimize total plant operation, the impact of, and the inter-relationships between thermal efficiency, plant emissions, and plant materials handling (e.g., waste disposal/sales) must all be simultaneously evaluated. With these goals in mind, DHR, NYSEG, and the Department of Energy (DOE) began development of PEOA™, an on-line plant emissions optimization advisor system designed to provide total plant monitoring and performance enhancement capabilities as an adjunct to the existing FTPA™ system developed previously by NYSEG and DHR personnel.

The FTPA™ system was originally developed by NYSEG and personnel from DHR Technologies in the late 1980's. FTPA™ was designed as a tool to assist plant operators, engineers and management to focus on areas of the plant where thermal performance (heat rate) could be improved, emissions reduced, and plant maintenance costs reduced. The system combined a computerized, on-line, intelligent plant performance monitor with both generic and plant-specific expertise to provide diagnostic assistance in the identification and analysis of these plant-related problems. The basic FTPA™ system has been operational since 1988. It is currently installed at NYSEG's Kintigh, Greenidge, and Homer City plants, and Portland General Electric's Boardman plant.

As the fossil utility industry headed into the 1990's, competition increased due to new regulations such as the Clean Air Act, as well as from independent power producers. These and other developments encouraged power plant management to search for new ways to optimize plant performance. In response to these new developments and as a natural evolution of FTPA™, NYSEG and DHR again teamed to develop PEOA™, an on-line process optimization system. PEOA™'s knowledge bases incorporate expertise from FTPA™'s electronic performance support system. PEOA™ is installed at NYSEG's Milliken Station.

Through careful planning and an awareness of emerging technologies, NYSEG and DHR have developed useful, powerful, and highly configurable performance support systems; FTPA™ and subsequently PEOA™. By leveraging the latest hardware and software engineering technologies, these products were placed in a strategic position to evolve with these technologies and provide even more powerful diagnostic, analysis and information management capabilities in a more cost effective manner. The development

of TOPAZ™ was a result of this evolution. Incorporating features from both systems, TOPAZ™'s modular design allows for installation of an on-line plant monitor, an advisor, and/or an optimizer for operators, engineers, and managers of process plants, depending on plant requirements.

TOPAZ™ is currently installed at City Public Service of San Antonio's Deely Units 1 and 2. NYSEG's Milliken Station is being upgraded to a TOPAZ™ system, and a proposal to upgrade their Kintigh system has been submitted.

### **TOPAZ™ Overview**

TOPAZ™ was designed to provide plant managers, operators, maintenance personnel and engineers with an effective tool for monitoring and diagnosing plant operating conditions. This on-line monitoring and diagnostic system allows plant operators and engineers to quickly understand the condition of the plant at all times, alert them to any changes in that condition, and recommend specific responses to operating problems. This results in improved plant reliability, availability, and reduced maintenance costs.

TOPAZ™'s platform independent, open client/server architecture allows the system to be easily integrated with existing legacy computing environments, such as local and wide area networks, digital control systems (DCS), programmable logic controllers, information and data highways, databases, and thermal performance monitors. This open design allows users to seamlessly integrate TOPAZ™ into existing information management systems, and eliminates the need to upgrade or enhance existing systems that may already be adequate.

The system is designed with three primary modules: an on-line Process Monitor, a Process Advisor, and a Process Optimizer.

### **Competitive Forces**

DHR's preliminary assessment of other commercially available optimization systems is described below. Cost comparisons were not available at the time this report was developed; however, with the assistance of NYSEG, competitive product pricing will be included in a future Topical Report.

- NUS's PMAX System - The PMAX system has been available for some time, and there are numerous installations. PMAX's greatest asset is NUS's name recognition. However, recent information indicates that NUS *may* be looking to get out of this business area, and PMAX has no emissions control features.
- Pegasus Technologies' and AI Ware's Functional Link Network (FLN) Combustion Optimizer - Very similar in design and function to PEOA™. Based on AI Ware's Functional Link Net neural network. For engineers it provides a process

design/optimization tool, while providing assistance to operators in monitoring and optimizing the combustion process.

- Black & Veach's OPM - Although DHR does not believe this product has emissions monitoring and advisory features, they are surely a strong competitor to the thermal performance features of TOPAZ™.
- AEP's Unnamed Product - not commercially available to other utilities.
- PowerMax's Ultramax - Similar in design to TOPAZ™ with limited on-line capabilities.
- Stone & Webster's NOx Emissions Advisor - Little known at this time.
- Southern Company and Radian Corp.'s GNOCIS - research underway
- New products not currently available commercially:
- Lehigh University's NOx Advisor
- EPRI/PTI's Emissions Management Module of PMW - EPRI's PMW workstation is a strong competitor of FTPA™ because EPRI member utilities are led to believe they receive EPRI software for "free". However, PMW's greatest assets are EPRI's name recognition, the perception that the software is free, and the performance calculations are generally perceived as the best available. It is too early to say whether the Emissions Management Module will be as competitive with the PEOA™ modules.
- LILCO, Grumman and ABB-CE's Unnamed Product

A comparison of the features of many of these competing systems was presented by at the EPRI/EESEERCO Optimizer Comparison Conference held in April, 1997. The comparison is shown in Table 7.4-1, below.

## **MARKET BARRIERS**

Market Barriers at this time are:

- Competition from similar products.
- Restriction on spending due to uncertainty from deregulation of the utility industry.

## **COMMERCIALIZATION PLANS**

DHR has evolved a sales and business planning model that DHR believes is extremely effective in:

- Identifying viable products and services,
- Researching and developing selected products and services,

- Marketing and selling developed products and services,
- Evaluating results, and
- Redirecting efforts as necessary.

This model is founded on several basic principles:

- Strategic Partnerships are essential to success.
- Cost Containment and Scheduled Attainment must be emphasized.
- Continual Research and Development efforts will be allocated the proper resources, and performed in a controlled manner.
- Marketing and Sales activities will be controlled, championed, funded, tracked, and redirected as necessary.
- All Activities will be Planned and Documented.

DHR's business model is "top-down" in design, with the cornerstone of its business and sales planning being the Company's Strategic Business Plan, which is updated periodically and reviewed and approved by DHR's Board of Directors. It is this plan that dictates the balance of DHR's planning, which is documented in DHR's:

- Marketing and Sales Strategic Plan,
- Divisional Technical Plans,
- Marketing and Sales Implementation Plans,
- Product Commercialization Plans,
- R&D Plan(s),
- Quality Assurance Programs, and
- Project Work Plans.

All of these plans are controlled documents with periodic updates and wide distribution to out-staff to ensure that "we are all on the same page".

The Commercialization Plan is one of the product commercialization plans listed above, and is an intricate part of DHR's overall sales and marketing planning.

The specific plans for TOPAZ™ in 1997, 1998, and 1999 are:



- Ads \$ 5,000/year
- Trade Shows \$ 5,000/year
- R&D \$ 150,000/ over 3 years
- Papers/Conferences \$ 10,000/year

Product advertisements will be strategically placed in various trade-publications throughout the year. Selection of the publications will be based on the publication's target audience, circulation, specific issue topics, and advertisement costs. In addition, press releases will be submitted for publication where appropriate. Other means of "free" advertising include presentation of papers at conferences, directory listings, articles, etc. The Company has also recently subscribed to Internet. As another way of advertising TOPAZ™ modules, DHR are developing a World Wide Web page (and subsequent attachments). The page(s) will be updated on the Internet on an as needed basis. DHR has already placed ads in Power Magazine and has received several qualified leads as a result.

Previously, DHR attempted to use an outside network of sales representatives; however, DHR were not successful in establishing additional sales. Currently, DHR's in-house sales and technical representatives will be used to capitalize on DHR's existing client base, as well to seek out new clients. DHR will present product demonstrations at trade shows and conferences, and on-site at client facilities as requested. TOPAZ™ DOS demo diskettes will be mailed to interested parties, along with additional product information (e.g., price sheets, tri-folds, product description, etc.) and the Company brochure. DHR is currently looking into the feasibility of producing the TOPAZ™ demo on CD ROM. In addition, DHR intends to team with strategic alliances/partners such as DCS manufacturers (e.g., Westinghouse, Honeywell) to promote TOPAZ™. These activities are all intended to increase the awareness of DHR's products among potential clients and to develop quality inquiries that lead to sales. Alliance work began the second half of FY97.

**Product Maintenance And Enhancement**

A key to successful product sales is the implementation of a well planned product maintenance and enhancement program. DHR has recently implemented strict policies and procedures with respect to this subject that it believes will significantly enhance future sales.

**Commercialization Goals**

DHR's marketing strategy will focus on illuminating the best product features of TOPAZ™. In particular, DHR will leverage the emissions monitoring and control features of TOPAZ™. TOPAZ™'s modular design allows the market place greater flexibility and

lower cost options by providing additional features not necessarily supported by some of the systems listed above.

The following are DHR's overall goals for the sale of the TOPAZ™ product line:

Five (5) Year Sales Goals

- Sales in 1997 \$100,000
- Sales in 1998 \$750,000
- Sales in 1999 \$1,000,000
- Sales in 2000 \$1,500,000
- Sales in 2001 \$2,000,000

DHR anticipates that the majority of these sales will be to the approximately 1,250 fossil fueled power plants currently operating at over 100 MWs in the United States. At a per plant average cost of \$100,000, which assumes the purchase of a minimum of two TOPAZ™ modules (i.e., a Process Monitor with either an Optimizer- or Advisor), this five (5) year plan will require the sale of 52 TOPAZ™ systems or 4.16% of the market.

DHR will attempt to capitalize on its existing client base, as well as seek out new clients. Of course, DHR's marketing and promotion efforts will also be directed at other industries and the international market in addition to the U.S. utility industry. However, it seems prudent to assume that for the present DHR's primary clients will continue to be U.S. utilities.

**Product Status And Current Sales Activities**

Product Status

Currently, TOPAZ™ is under final development at NYSEG's Milliken Station. Phase 1 and 2 were delivered in April 1997. Final installation of a full TOPAZ™ system (Phases 3-5) was tentatively scheduled for 4Q, 1997, dependent on timely approval of each Phase. Several upgrades are also underway including the system to client/server environment which were scheduled for completion in late 1997.

Marketing Status

TOPAZ™ marketing began in earnest at the end of 1994 with two significant mailings and demonstrations at several trade shows (e.g., Clean Coal Conference) and at several utilities (American Electric Power Service Corporation, etc.). In addition, numerous papers have been written, published and presented at conferences and trade shows. Current leads include possible alliances with DCS manufacturers. For example, DHR teamed with Westinghouse on a presentation in Israel in September of 1996. In addition, DHR recently received a request for TOPAZ™ information from Parsons Power for their

current project in Korea. DHR also has active sales activities with GPU/Genco, IL Power and Pacific Corporation. One half page ad was placed in Power Magazine in the April issue to coincide with a Milliken profile.

DHR will provide NYSEG with a quarterly report on TOPAZ™ including all current marketing and sales efforts. HR also plans to conduct progress meetings when needed, both internally and with NYSEG representatives.

**TABLE 7.4-1**  
**EPRI/SEERCO OPTIMIZER COMPARISON CONFERENCE**  
 April 9 & 10, 1997

ITEM	Ultramax	Lehigh's Boiler Op	Pegasus's NeuSight	SEI's GNOSIS	Praxis's PECOS	DHR's TOPAZ
Boiler Optimization	Yes	Yes	Yes	Yes	Under Development	Yes
Total Plant Optimization	No	No	No	No	Under Development	Yes
Optimization Objective	NOx + HR	NOx or HR	NOx + HR	NOx + HR	NOx + HR + Cost	NOx + HR + Cost
Steady State Optimization	Yes	Yes	Yes	Yes	Under Development	Yes
Closed Loop <sup>1</sup>	Under Development	No	Yes for Load Changes ≤ 1%	Yes for Load Changes ≤ 1%	Under Development	Under Development
Supervisory	Yes	Yes	Yes	Yes	Under Development	Yes
Off Line & One Time <sup>3</sup>	Yes + Low Cost	Yes + Low Cost	Yes	Yes	Under Development	Yes
Model Type	Statistical	Neural Net	Neural Net	Neural Net	Neural Net	Neural Net
Load Range & Equipment Combination	1 Model per Scenario	1 Model per Scenario	1 Model for all	1 Model for all	1 Model for all	1 Model for all
Different Fuels	1 Model per Scenario	1 Model per Scenario	1 Model per Scenario	1 Model per Scenario	1 Model for all	1 Model per Scenario
Field Device Status	No	No	No	No	No	Yes for Advisor
Commercial Status	Optimizer Available	Optimizer Available	Optimizer Available	Optimizer Available	Fuel Blend Mod Avail; HR, Emissions & Steam Cycle Mods under Development	Monitor + Advisor Available; Optimizer being Demonstrated
Networking	No	No	No	No	Under Development	Yes
Open Architecture	No	No	No	No	Under Development	Under Development
Optimizer License Cost/Unit	\$40K to 60K	\$25K to 55K (per Site)	\$ 130K Supv; \$ 230K Closed Loop	\$ 180K Supv; \$ 230K Closed Loop	\$ 300K (All Modules)	63K+20K for Perf Calc
On Line Data Validation	No	No	Yes, but Minimal	Yes, but Minimal	Under Development	Yes + Enhancement Under Dev
Retraining Model	Auto <sup>2</sup>	Manual	Manual	Manual	Manual	Manual
Model Train Time	2 Weeks	2 Weeks	18 to 20 Weeks	18 to 20 Weeks	18 to 20 Weeks	18 to 20 Weeks
Systems Installed	60 <sup>4</sup>	7 <sup>4</sup>	3	3	1 - Fuel Blending Module	4 - FTPA + Implementing 2 Optimizers
EPRI's Suite for Optimization	Yes	No	No	Yes	No	No

## **7.5 NOxOUT® NON-SELECTIVE CATALYTIC REDUCTION SYSTEM**

### **MARKET ANALYSIS**

The NOxOUT® Selective Non-catalytic Reduction (SNCR) process offered by Fuel Tech, Inc. (recently restructured from the Nalco/Fuel Tech Joint Venture) is a new chemical and mechanical system for cost-effective NO<sub>x</sub> reduction from fossil-fueled and waste-fueled combustion sources. The process includes the proprietary computer codes to ensure that the urea-based reagent is optimally distributed in the boiler, the control hardware and software to enable the process to follow boiler load changes by altering the flow rate and chemical composition of the reagent, and the necessary chemical feed, storage, mixing, metering, and pumping systems. The key features of the NOxOUT® technology which make it marketable are its low capital cost, its use of proprietary chemicals to increase the temperature range over which the process chemical reactions are effective, and its consistent rate of NO<sub>x</sub> removal with a very low ammonia slip.

From 1976 to 1981, research sponsored by the Electric Power Research Institute (EPRI) established that urea was an effective agent to convert NO<sub>x</sub> into harmless nitrogen, carbon dioxide, and water. The urea/NO<sub>x</sub> reaction takes place only in a narrow temperature range, 1600 °F to 2100 °F, below which ammonia is formed and above which NO<sub>x</sub> emission levels actually increase. The NOxOUT® process uses a urea solution enhanced by proprietary chemical additives and mechanical modifications to broaden and shift the temperature range over which the process is effective and to control the formation of ammonia. The use of this enhanced formulation allows NOxOUT® to be injected at various elevations of the boiler, reducing the number of new injection penetrations that have to be installed. Since the location of the injection points is less critical with the enhanced solution it is expected that no additional injection points may be required on a boiler besides the original inspection ports. Injecting NOxOUT® at different elevations allows the NO<sub>x</sub> to be removed in stages, with a portion of the required NO<sub>x</sub> being removed at each level.

The chemical enhancers included in the NOxOUT® solution also allow ammonia slip to be maintained below 2 ppm. Typically, a simple urea injection would have significant levels of ammonia being formed as a side reaction to the NO<sub>x</sub> reaction. The ammonia can result in increased air heater plugging or can collect on the fly ash collected in the ESP and prevent the commercial sale of the fly ash. By maintaining the ammonia slip to such a low concentration these problems are avoided.

The NOxOUT® system is a low capital cost NO<sub>x</sub> reduction method. The only capital equipment included in this process is a pumping skid, urea storage tank, injection piping and nozzles, and control systems. These costs provide substantial advantage over the cost of selective catalytic reduction technology which can be an order of magnitude higher.

Since the injection of the NOxOUT® solution does not impact the combustion process, the system can be applied in conjunction with all combustion modification technologies to improve reductions in NO<sub>x</sub>. NOxOUT® used in this fashion is expected to reduce NO<sub>x</sub> by an additional 30%, compared to that achievable with combustion modifications alone. This further reduction is important in that combustion modifications are not expected to be able to reduce NO<sub>x</sub> emissions to the 0.45 lb/MM Btu level required by the CAAA in all applications. Also, local or regional regulators may require stricter emission limits than the CAAA. These lower limits may only be achievable through the utilization of control technologies, such as NOxOUT®, that can be applied in conjunction with combustion modifications.

Prior to the Milliken project the NOxOUT® process had been commercially demonstrated on both industrial and utility boilers. However, the MCCTD project was to be the first application to apply the NOxOUT® process coal in conjunction with combustion modifications on a tangentially fired boiler firing high sulfur. The project planned to use combustion modifications as the primary technology for NO<sub>x</sub> reduction and the NOxOUT® process to demonstrate its NO<sub>x</sub> removal capabilities. The NOxOUT® demonstration was intended to show that NO<sub>x</sub> can be removed, with a high degree of repeatability, while keeping levels of ammonia in the fly ash below 2 ppm. The demonstration was also intended to show that fly ash used as pozzolanic material in concrete, in lieu of landfilling, would not be affected by the application of the NOxOUT® process.

## **APPLICABILITY OF THE TECHNOLOGY**

Market applications for the NOxOUT® process resulting from the MCCDT project include any tangentially fired boiler that fires medium to high sulfur coal. Additional demonstration of the technology would be expected to expand the market to all types of boilers, including cyclones and stokers. The Milliken demonstration size is 150 MW (1527 million Btu per hour). However, NOxOUT® can be used very effectively on a wide range of boiler sizes and configurations. Experience in Europe has included installations ranging from as low as 130,000 pounds of steam per hour to over 900 million Btu per hour. The size of the application is not limited by the size of the NOxOUT® system since the system is modular and can be made as large, or small, as required. The NOxOUT® system could be used in conjunction with, or in lieu of, combustion modifications, selective catalytic reduction (SCR) units (to reduce the size of the SCR system) or low NO<sub>x</sub> burners.

## **MARKET SIZE**

The NOxOUT® SNCR technology potentially has a wide market appeal. A fully detailed analysis of the potential market this technology is provided in Volume I of the *Public Design Report*. The results of this analysis are summarized in table 7.5-1. The technology boundary conditions for the NOxOUT® process are larger than that for the SHU FGD technology since, in addition to coal fired units, the process can be used with

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oil and gas fired plants. Therefore, the potential retrofit market is only limited to fossil units currently in service which will not be retired before 2030. NOxOUT® injection technology also applies to all new fossil fuel fired power plants.

The market penetration for the NOxOUT® SNCR technology was assessed in a similar fashion to that of the SHU process. Table 7.5-1 shows the share of the utility NO<sub>x</sub> control market that the NOxOUT® SNCR technology is estimated to capture. A projection of 35 years, from 1996 to 2030, is presented in five year increments. Each year's fractional shares depends on the previous year's fractional shares. This means that an initial market share for the technology is required and must be assumed to stimulate a market. A 1.5 percent share was assumed. This is considered realistic in that it shows that an outside force, such as the Milliken project or an initial investment, is needed before the product becomes accepted. Based on this analysis, the NOxOUT® SNCR technology has the potential of increasing its share of the utility market to approximately 24 percent by the year 2030. The projected NOxOUT® SNCR market share for retrofits in the U.S. through the year 2030 totals 4624 MW. The projected NOxOUT® SNCR market share in the U.S. for new power plants through 2030 totals 105,582 MW.

**TABLE 7.5-1  
ESTIMATED MARKET PENETRATION FOR NOxOUT® SNCR SYSTEM**

Year	Five Year Avg. share
1996-2000	0.020
2001-2005	0.031
2006-2010	0.048
2011-2015	0.073
2016-2020	0.111
2021-2025	0.165
2026-2030	0.239

**MARKET BARRIERS**

The NOxOUT® selective non-catalytic reduction (SNCR) is an EPRI patented process which can provide significant NO<sub>x</sub> emission reduction, depending on boiler temperature profile and NO<sub>x</sub> inlet loading, among other factors, using urea as the reactant chemical. Urea decomposes into ammonia and reacts with the NO<sub>x</sub> to produce nitrogen, carbon dioxide and water. The method of NO<sub>x</sub> removal is to inject the urea-based solution into the gas stream. The nitrogenous species in the solution react with the NO<sub>x</sub> in the flue gas to reduce it to nitrogen.

The temperature range of successful application is from 1600 to 2100 °F. Practical applications have shown that injection on the high side of the temperature window (e.g., 1900-2100°F) is preferred to limit NH<sub>3</sub> slip and provide increased mixing and vaporization time. In order to determine the proper location for injection, temperature mapping of the

boiler at varying loads must be established. The system supplier would then determine the best locations for injection and determine the expected performance based on chemical kinetic and computational fluid dynamics modeling. Due to changes in boiler temperature profiles with changing load, it is typical that multiple injection points would be required, with controls to change the injection location to follow the optimum temperature. The reagent is delivered as a 50 percent solution of urea in water, combined with additives. The reagent may be further diluted with water prior to injection for either process control or to enhance its storage properties.

Typically, NO<sub>x</sub> emission reduction is in the range of 25 to 45 percent, depending on various factors which include:

- Inlet NO<sub>x</sub> levels
- Location of the optimum temperature window (furnace or convective section)
- Fuel type
- Furnace gas temperature profile
- Furnace gas flow distribution
- Furnace excess air
- Boiler load.

Factors which contribute to good NO<sub>x</sub> reduction include:

- Furnace location of the optimum temperature window
- Long residence times within the temperature window
- Good chemical dispersion and mixing in the injection zone
- High initial NO<sub>x</sub> levels (e.g., > 300 ppm)

Because the size of the boiler is a significant factor in achieving good chemical mixing and dispersion, lower NO<sub>x</sub> removal efficiencies can be expected with larger units.

The disadvantage of the NOxOUT® process, as with any SNCR process, is ammonia slip. This will vary with inlet NO<sub>x</sub> loading, NO<sub>x</sub> reduction, and reaction temperature but typical values range from 5 ppm to 10 ppm. The basis of the design for the MCCTD project was 2 ppm slip resulting in less than normal NO<sub>x</sub> reduction. Impingement of urea and resulting fire side erosion/corrosion is also a concern. Proper design of the injection system is necessary to avoid such problems. Air heater fouling with ammonium bisulfate salts is a concern when firing high sulfur fuels.

Additional process penalties will arise from the vaporization of urea or the additional energy penalties from high levels of atomization air. Although the delivered urea solutions are typically 50 percent solutions, the injected solution is significantly diluted to



allow efficient atomization and chemical dispersion. The concentration may also be varied with process parameters to provide constant atomization properties with variable injection rates. The losses associated with vaporizing the water will depend on concentration, but are typically a 0.3 percent reduction in boiler efficiency. Some urea injection systems may utilize relatively high amounts of air to improve chemical mixing with the flue gas. Rates can be as high as 1.5 to 2 percent of the boiler gas flow. This can decrease boiler efficiency at the order of 0.1 percent.

A properly designed urea or ammonia injection system should have no significant effect on boiler performance or reliability. However, the use of high levels of air to supply mixing energy for the injected reagent may alter heat transfer and boiler efficiency. Effects will be highly site-specific, since steam side impacts depend upon current unit operating conditions. Depending on the specific atomizer design, the transport air can be as high as 4.0 percent of the flue gas flow. These flow rates can significantly affect process economics. Maintenance would increase to maintain the injectors and injection system in proper repair.

Concerns of air heater deposit problems may arise in high sulfur coal applications. Deposits can form at gas temperatures of about 550 °F when NH<sub>3</sub> levels exceed 5 ppm. These deposits typically occur in the intermediate temperature baskets of the air preheater. Plume opacity problems can arise with higher NH<sub>3</sub> slip levels and high concentrations of either SO<sub>2</sub> or HCl (e.g. > 30 ppm). Plume visibility could become an issue when gas temperatures drop and either ammonium chloride or sulfate is formed. In these cases, a highly visible white attached or detached plume can be created. Since chloride in the flue gases cannot generally be controlled limiting NH<sub>3</sub> slip is the only means available to mitigate plume formation.

Regarding performance, the full scale utility SNCR experience to date has yielded a wide range in performance, some of which has been attributed to site specific conditions which affect the application of the SNCR technology. The following comments apply to urea and ammonia based system and are the result of the limitations imposed by the retrofit installations in existing boilers. The process effectiveness will be highly dependent upon location of the optimum temperatures within the boiler, if convective section tube surfaces are located nearby, and the available locations for injector installation. Based on these experiences, the following guidelines can be provided:

- It is important to accurately determine the temperature window location in the furnace during the design stage, as a function of both load and fuel type.
- Applications where the temperature window occurs in the furnace, or near the furnace exit, provide the optimum opportunity of SNCR NO<sub>x</sub>. Conversely, if the temperature window occurs in the convective section, NO<sub>x</sub> reductions are more likely to be lessened due to limited residence times.

- Adequate residence times within the optimum temperature window are required for reagent mixing and distribution. Insufficient residence times may be expected when optimum temperatures exist in the boiler convective sections.
- Smaller units (less than 150 MW) have historically yielded higher NO<sub>x</sub> removals than larger units. Larger units will pose greater problems to the optimization of the reagent injection. Factors such as high heat release rates, compact furnace and convective section designs, and large width and/or depth of the gas flow path can degrade process performance. A combination of these factors may make SNCR application impractical on some large units.
- The injection system design should incorporate flexibility to allow optimization of reagent injection during start up testing. Modeling of the reagent injection may be desirable to optimize or design the injection system.
- NO<sub>x</sub> reductions are comparable using urea or ammonia based chemicals, although the limited available data suggest that ammonia slip is lower with ammonia based chemicals.
- N<sub>2</sub>O emissions are higher with urea (10-40 percent of the NO<sub>x</sub> reduced) than with ammonia (less than 5 percent of the NO<sub>x</sub> reduced).
- The use of SNCR, utilizing either ammonia or urea injection, may impact unit CO emissions. In some instances, CO emissions have increased when urea was injected. The increase has been variable, with up to 20 percent of the CO contained in the urea being emitted. However in most demonstrations, no significant increase in CO emissions has been noted.

Ammonia slip level restrictions can be different, depending on the location of the installation and associated local concerns for NH<sub>3</sub> emissions. The trend is to lower NH<sub>3</sub> slip, and where limits do not presently exist, it is likely that they will in the near future. Lower NH<sub>3</sub> slip will tend to lower the NO<sub>x</sub> reduction capability of this technology.

The NOxOUT® process has an extensive experience list, but application to large utility boilers is in the demonstration category, therefore, the technology is not considered mature, but is developing. Many of the NOxOUT® demonstrations have been conducted on gas- or oil-fired boilers, while only a few coal-fired demonstration have been performed to date. In the past few years Naico Fuel Tech has been the only SNCR supplier active in the utility coal fired U.S. market. Initially Naico Fuel Tech marketed only smaller units but have recently extended their market to larger units. The largest demonstration to date was completed at the PSE&G Mercer unit, a 321 MW Foster Wheeler continuous slagging, twin furnace unit. A demonstration is on-going at the GPU Seward unit, a 147 MW CE tangentially fired boiler. Demonstrations are planned in 1998 for the 600 MW AEP Cardinal unit. Heat mapping and modeling have been performed for the 750 MW PP&L Brunner Island unit. Commercial operation is planned for the 600 MW PSE&G Hudson unit in May 1999.

## **ECONOMIC COMPARISONS WITH COMPETING TECHNOLOGIES**

As a stand-alone technology, the NOxOUT® process could have the lowest cost per ton of NO<sub>x</sub> removed when the consequences of other technologies are considered.

The use of combustion modifications alone for NO<sub>x</sub> emissions reduction, either over-fired air ports or low NO<sub>x</sub> burners, has several operational and economic disadvantages compared to their use in combination with a NO<sub>x</sub> emissions trim technology such as NOxOUT®. Combustion modifications usually increase the amount of carbon in fly ash, commonly referred to as loss on ignition (LOI), and can cause severe changes in the slagging characteristics of the boiler. Utilities that are concerned about the quality of their fly ash and the performance and reliability of their boilers may use the NOxOUT® trim control system. Fly ash with low LOI's can be used as a pozzolanic material in the manufacture of concrete. The sale of ash significantly reduces the amount of solid waste that must be disposed, or landfilled. As an example, Milliken Station typically sells 90 percent of the fly ash produced. The sole use of combustion modifications to reduce NO<sub>x</sub> could double the carbon content of the ash, causing the fly ash to be unmarketable. Consequently, any utility that is interested in reducing solid waste may choose to limit NO<sub>x</sub> reductions achieved by combustion modification to a level consistent with fly ash sales and use the NOxOUT® process to trim the NO<sub>x</sub> to the desired level. In order to reduce LOI with combustion modifications, the utility would be forced to install new pulverizers to produce a more finely ground coal. The coal would have to be reduced from 70 percent through a 200 mesh screen to 90 percent through the screen. The combination of overfired air ports or low NO<sub>x</sub> burners and the installation of new mills would involve a greater capital expenditure than the installation of the NOxOUT® system.

The slagging problems that could be experienced by combustion modifications cannot be predicted accurately. Increased slagging in the furnace would increase the furnace exit gas temperature (FEGT). Recently studies suggest that the temperature could be increased by as much as 100 to 200 °F due to furnace heat absorption as a result of different levels of slagging in the furnace. The higher steam temperatures prior to the finishing superheat/reheat may require attemperation, which reduces cycle efficiency, to maintain steam conditions at the turbine inlet. The higher FEGT will cause increases in back-pass temperatures. The flue gas exit temperature will increase which reduces boiler efficiency. The use of the NOxOUT® process in combination with combustion modifications may reduce excessive slagging in the furnace while achieving design NO<sub>x</sub> emission reduction.

Another problem with combustion modifications is the risk of losing the flame in staged combustion modifications. With overfired air ports, the burners will operate with very low excess air. Any problems in the burner control systems, or operator error, could produce a hazardous condition if the flame were lost. Excess air must be strictly controlled to prevent flame-out, if excess air is low. If excess air is too high, NO<sub>x</sub> could be increased. The combination of NOxOUT® with combustion technologies will allow higher

combustion oxygen levels and hence better boiler performance while maintaining NO<sub>x</sub> levels similar to those achieved by operating at low oxygen levels.

Finally, combustion modifications can increase carbon monoxide (CO) in the flue gas if operators do not closely monitor boiler performance. CO is a greenhouse gas and an indicator of incomplete combustion and lost efficiency.

Rather than relying solely on combustion modifications, utilities will have the incentive to consider using NOxOUT® in combination with combustion modifications because this combination has the lowest capital cost per ton of NO<sub>x</sub> removed the least effect on boiler slagging, air heater fouling, and cold end component corrosion. It maintains boiler and cycle efficiency, it requires the least monitoring and control, and it is the safest NO<sub>x</sub> removal technology with reduced risk of losing the boiler flame or "puffing" the boiler.

Selective Catalytic Reduction (SCR) is the other NO<sub>x</sub> removal technology that would be considered for large scale NO<sub>x</sub> reduction. SCR installations have a very high capital cost. Typically, SCR installations are so large that they cannot be installed inside the boiler building. As an example, an SCR installation for the Milliken Station would require an area of 2400 square feet and would be sixty to seventy feet high. The installation would require significant structural steel and would weigh approximately 500 tons. Since the SCR would be external to the plant, new duct work would have to be installed between the economizer and the air heater, assuming hot side SCR were installed. If cold side SCR were installed, the flue gas would have to be reheated to 650°F, which would reduce plant thermal efficiency. SCR would increase the pressure drop across the system and could require significant induced draft fan upgrades. SCR catalysts have a predicted life of only five to six years and significantly increase the solid waste production of the plant when the catalyst is replaced. Also, the spent catalyst is a hazardous waste and cannot be landfilled in the same manner as fly ash, assuming that a non-regenerable catalyst is used. Finally, hot side SCR installations can promote the formation of ammonium bisulfate in the air heaters and can cause air heater fouling and increased particulate loading on the particulate air control device, which inevitably increases solid waste production.

The NOxOUT® system will be considered for use by utilities that want to reduce NO<sub>x</sub> emissions reliably, safely, and consistently, with the lowest capital and operating costs and the lowest production of solid wastes.

## **COMMERCIALIZATION PLANS**

Prior to the MCCTD project the NOxOUT® technology was installed, or was in the planning stages, on approximately 30 boilers ranging in size up to 900 million Btu/hr. However, none of these installations used high-sulfur coal. Thus, this project was the first commercial demonstration of the NOxOUT® technology on a furnace firing U.S. high-sulfur bituminous coal. The successful demonstration of the ability of this technology to achieve emission reductions below 0.45 lb/mmBtu on a high sulfur, pulverized coal

utility plant was expected to provide the catalyst for commercialization. The commercialization of the technology is expected to proceed quickly based on the successful completion of this project. Utility plants similar to Milliken requiring reductions beyond that provided by combustion modifications alone or those plants wishing to avoid the problems of combustion modifications when used alone will consider using the NOxOUT® technology.

NO<sub>x</sub> regulatory requirements will have also have an impact on the commercialization of the technology. Establishment of this technology as a low cost impact with minimal energy and environmental concerns should lead to this technology being chosen as the basis for compliance. If so established, this process will be required for many old plants as a retrofit and for new plants.

Commercialization will also be assisted by Nalco Fuel Tech's strong support in the commercialization of this project. Prior to the project steps had already been taken to contract U.S. licensees to provide the NOxOUT® chemical in the U.S. These licensees included UNOCAL, CARGILL, ARCADIAN, NITROCHEM, and W. H. SHURTLEFF. The availability of these licensees demonstrates the impact that this technology will have on the U.S. chemical industry and the ease at which commercialization will be established.

In the past few years Nalco Fuel Tech has been the only SNCR supplier active in the utility coal fired U.S. market. Initially Nalco Fuel Tech marketed only smaller units but have recently extended their market to larger units. The largest demonstration to date was completed at the PSE&G Mercer unit, a 321 MW Foster Wheeler continuous slagging, twin furnace unit. A demonstration is on-going at the GPU Seward unit, a 147 MW CE tangentially fired boiler. Demonstrations are planned in 1998 for the 600 MW AEP Cardinal unit. Heat mapping and modeling have been performed for the 750 MW PP&L Brunner Island unit. Commercial operation is planned for the 600 MW PSE&G Hudson unit in May 1999.

As of May 1, 1998, Fuel Tech N.V. acquired the Nalco interest in the Nalco/Fuel Tech Joint Venture. The Joint venture will operate as Fuel Tech, Inc., a majority owned subsidiary of Fuel-Tech N.V. Fuel Tech N.V. is committed to providing quality NOxOUT® NO<sub>x</sub> abatement systems.

**8.0 CONCLUSIONS AND  
RECOMMENDATIONS**

## **8.0 CONCLUSIONS AND RECOMMENDATIONS**

### **8.1 PLANT ECONOMIC OPTIMIZATION ADVISOR**

The Plant Economic Optimization Advisor (PEOA) is an on-line performance support system developed by DHR Technologies, Inc. to assist plant personnel in meeting the requirements of Title IV of the 1990 Clean Air Act Amendments and in optimizing overall plant economic performance. The PEOA system was installed on both Milliken units. The system integrates key aspects of plant information management and analysis to assist plant personnel with optimization of overall plant economic performance, including steam generator and turbine equipment, emissions systems, heat transfer systems, auxiliary systems, and waste management systems. The system is designed primarily for plant operators but also provides powerful, cost-saving features for engineers and managers. The PEOA automatically determines and displays key operational and control setpoints for optimized cost operation. The system provides operators with on-line emissions monitoring and diagnostic capabilities, along with rapid access to reports and trend information. The PEOA optimization algorithms evaluates key data emissions parameters, such as NO<sub>x</sub>, SO<sub>2</sub>, O<sub>2</sub>, CO, CO<sub>2</sub>, Carbon in Ash, and Opacity, plus other operational parameters such as boiler and turbine mixing. The system provides "what-if" capabilities to allow users to utilize the optimization features to evaluate various operating scenarios. In addition to providing optimized setpoint data, the PEOA system also provides plant operators and engineers with expert advice and information to help optimize total plant performance.

#### **8.1.1 MAJOR TECHNICAL FINDINGS**

The demonstration and testing program demonstrated the capability of the PEOA to smoothly integrate with power plant distributed control system, performance monitoring and information systems on a variety of network topologies, operating systems and hardware platforms.

PEOA uses a neural network to model the plant and then uses the model to find the least-cost operating conditions given certain constraints. A neural network "learns" the relationships between its inputs and outputs by using past data. Therefore, the data must be good to expect good results from the network model. Originally, the Online Performance Monitor (OPM) was to provide data validation for PEOA, as well as calculations and graphical representations of plant performance. The OPM system was dropped from the demonstration program due to cost considerations, requiring the PEOA to perform its own calculations and requiring that data validation be performed manually or by software system.

Capturing a good set of training data was a problem that plagued the program from the start. As a consequence, NYSEG undertook the task of reviewing all data points and ensuring that the information about them was accurate. This entailed starting at the physical instrument and working through the system to the point where the final value is stored in the database.

Two tests were initially conducted using PEOA, one short-term (about 3 hours) and one long-term (48 hours). Results of these tests were promising but inconclusive. Excerpts from these test report are included in Section 4.2.1. Also, for a variety of reasons, some recommendations during the 48-hours test produced some surprising and undesirable conditions. These tests failed to prove PEOA as a useful tool at Milliken and the users were skeptical of it. In response, certain program changes were implemented, resulting in the following phased approach.

**Phase 1: Showing PEOA Works.** This phase included only the steps necessary to get the neural network model functioning, providing recommendations and answering management questions. Included were updating the PEOA server to access the new VAX configuration, adding the process calculations to replace functions formerly provided by OPM and integrating the PEOA cost calculations to provide links between all calculations. These steps were performed on one stand-alone machine. Networking, remote connection and user interface issues were not to be addressed until the usefulness of the tool had been proven.

**Phase 2: Performance Monitor with Data Validation.** This phase provides a graphical display which makes the interface much more user-friendly (and more likely to be used). Data validation saves valuable manpower in sifting through the training data sets.

**Phase 3: Compiled Calculations.** This improves the speed of the optimization (as much as 100-fold).

**Phase 4: Network the System.** This provides PEOA capabilities to all network users (possibly at lower cost than individual stand-alone systems).

**Phase 5: Full TOPAZ System.** This builds all three TOPAZ modules on the Gemini platform.

Reports of performance testing of the modified PEOA system were not available at the time of publication of this report. When available they will be included in a future topical report.

### **8.1.2 COMMERCIALIZATION POTENTIAL**

TOPAZ™ is a software product that has evolved from the development of the Fossil Thermal Performance Advisor (FTPATM) and Plant Economic Optimization Advisor (PEOATM). This product line is currently licensed to DHR under a NYSEG License Agreement dated February 19, 1997. TOPAZ™ includes the very best features of FTPATM and PEOATM, and has been packaged into stand alone modules with options to allow the marketplace greater flexibility. The principal modules of TOPAZ™ are:

- Process Monitor
- Process Optimizer



- Process Advisor
- Editor

Previous efforts to market TOPAZ™ have focused on the benefits derived from FTPA™, primarily heat rate efficiency. Because of the current industry emphasis on emissions control, and due to new regulations such as the Clean Air Act, the emissions monitoring and advisory features of PEOA™ are also in high demand.

The plan for commercializing PEOA™ focuses on leveraging the emissions monitoring and control features of TOPAZ™ through several means including implementation of a vigorous promotional advertising campaign, combined with complementary presentations at various conferences and potential client facilities and teaming with strategic alliances/partners such as DCS manufacturers to promote TOPAZ™. TOPAZ™'s modular design allows the market place greater flexibility and lower cost options by providing additional features not necessarily supported by some of the systems listed above.

The following are DHR's overall goals for the sale of the TOPAZ™ product line:

Five (5) Year Sales Goals

- |                 |             |
|-----------------|-------------|
| • Sales in 1997 | \$100,000   |
| • Sales in 1998 | \$750,000   |
| • Sales in 1999 | \$1,000,000 |
| • Sales in 2000 | \$1,500,000 |
| • Sales in 2001 | \$2,000,000 |

DHR anticipates that the majority of these sales will be to the approximately 1,250 fossil fueled power plants currently operating at over 100 MWs in the United States. At a per plant average cost of \$100,000, which assumes the purchase of a minimum of two TOPAZ™ modules (i.e., a Process Monitor with either an Optimizer- or Advisor), this five (5) year plan will require the sale of 52 TOPAZ™ systems or 4.16% of the market.

DHR will attempt to capitalize on its existing client base, as well as seek out new clients. Of course, DHR's marketing and promotion efforts will also be directed at other industries and the international market in addition to the U.S. utility industry. However, it seems prudent to assume that for the present DHR's primary clients will continue to be U.S. utilities.

The success of this product will be monitored at least quarterly and DHR will redirect its efforts as appropriate. Subsequent sections of this plan provide additional details concerning DHR's current commercialization goals and objectives, and plans for implementation of these goals and objectives.

## **8.2 VALIDATION OF BRIGHAM YOUNG UNIVERSITY 3D COMBUSTION CODE**

The PCGC-3 combustion model is a comprehensive computer model (3 dimensional) developed under funding from the National Science Foundation to Brigham Young University and the University of Utah through the establishment of an Advanced Combustion Engineering Research Center. The mission of ACERC is to develop advanced combustion technology through fundamental engineering research and educational programs aimed at the solution of critical national combustion problems. These programs are designed to enhance the international competitive position of the U.S. in the clean and efficient use of fossil fuels, particularly coal. The Center is joined and supported by 24 industrial firms, three US government centers, the State of Utah and three other universities.

The model developed by ACERC was used to optimize the operation of the combustion equipment, especially the design of the combustion modifications to the furnace. Through the use of the model, the project was able to demonstrate on the utility scale the validity of the model and quantify the NO<sub>x</sub> reduction achieved through its use.

A study was performed by ACERC using the Milliken Station Unit #2 furnace to compare test data from a large-scale electric utility boiler with predictions from the coal-qualified PCGC-3 combustion code. The anticipated products of the ACERC test program were two-fold. The tests were intended to evaluate the capability of comprehensive codes for large-scale boiler simulation. Once validation is well along, the combustion codes can be used to improve the operation and upgrading of existing power plants as well as to provide guidance for future power plant designs and pollutant retrofits. Thus, the key product from this effort is a documented assessment of 3-D combustion code reliability in predicting furnace behavior.

At Milliken station, twenty-one prediction cases were run, of which twelve are presented in the ACERC final report. The cases not presented were for the smaller size grid cases (65K nodes) where prediction results indicated that grid independence was not achieved.

Full-scale power plant testing provides practical process data for evaluation of combustion models and helps to assure that the sub-models used in the code are adequate to model the physical processes on a large scale. This is especially true of 3-dimensional (3-D) models under development at ACERC and elsewhere which require increased computing power and more exacting convergence and stability criteria and hence more thorough evaluation using 3-D measured data. The coal-qualified version of PCGC-3 demonstrated good prediction comparisons with the 1991 Goudey Station test data as reported previously. The next phase of PCGC-3 validation was to make predictions and measurements for the Milliken Station pulverized coal boiler. The Milliken Station boiler is twice the size of the Goudey Station, with a rectangular boiler cross section and newly installed low NO<sub>x</sub> burners. The test data for the Milliken Station were obtained in July, 1995. A series of reports were delivered by ACERC to NYSEG that

included the Field Measurement Report (NYSEG 1995) and the Comparison Report (NYSEG 1997). These reports are available from NYSEG upon request.

Spatially resolved, point-for-point comparisons are presented in the Comparison Report between Milliken Station predictions and measurements for gas composition ( $\text{CO}_2$ ,  $\text{CO}$ ,  $\text{SO}_2$ ,  $\text{NO}_x$ ,  $\text{O}_2$ ), gas temperatures, gas and particle velocities and particle composition. Where available, turbulence intensities are also presented. Probe traverse averages and boiler level averages at the Milliken furnace are also presented for the same variables. Comparisons are presented for the effects of grid size, over-fire air injection point and flow rate, and ignition point variation. Initial particle size distribution was obtained from data and the low- $\text{NO}_x$  burner geometry was obtained from construction drawings. Grid density, limited by computational time requirements and ABB/CE proprietary restrictions, did not allow more detailed geometrical modeling of the burner input parameters, though near-field measurements in the burner were made to help alleviate this deficiency.

In general, combustion code computations show acceptable trends with very good point-for-point comparisons in the far-field but less reliable comparisons in the near-burner field. This in-exactness in the near-field is attributed to the crude nature of the largest grid (337K nodes), even with variable grid spacing, being unable to represent the construction drawing details in the burner-input region. Lack of geometrical detail of the burner ports configuration, and lack of precise mass distribution information between primary coal/air, auxiliary air, over-fire air, and concentric firing air flow rates are also contributing factors.

The conclusions from this phase of the ACERC study are:

- Full-scale furnace testing with sensitive laboratory instruments can be successful and internal evaluation of such data gives assurance as to the data's accuracy.
- A larger number of grid nodes is required for 3-D combustion model solutions to yield adequate predictions for a boiler as large as Milliken Station.
- The coal devolatilization rate constants (ignition point location model) have a significant influence on the predicted results, especially in the near-field.
- Far-field comparisons between measured and predicted data are better than near-field comparisons. Analysis suggests that near-field comparisons can be improved with larger numbers of grid nodes and improved code sub-models.
- Trends for important variables like  $\text{NO}_x$  and carbon-in-ash are correctly represented, but quantitative comparisons can be improved, especially in the near-field.
- Continued efforts in evaluation of computerized computational methods should yield improved comparison results. Emphasis will need to be placed on improved near-field

burner geometric models, turbulence intensity models, grid size effects, and more precise wall heat flux predictions.

These comparison results suggest that computerized predictions of large-scale utility furnaces can successfully be made. This is particularly encouraging considering the vast number of computations that a code must execute without error to accomplish these kinds of predictions.

### 8.3 MILLIKEN LNCFS-3 EVALUATION

The project's NO<sub>x</sub> emissions control strategy included combustion modifications to minimize NO<sub>x</sub> emissions and simultaneously optimize boiler thermal efficiency. NYSEG installed Low-NO<sub>x</sub> Concentric Firing System (LNCFS) burners. The burners are controlled by the boiler control system to optimize combustion efficiency while minimizing NO<sub>x</sub> emissions.

The objective of the LNCFS-3 evaluation program was to supplement and confirm earlier demonstrations of the LNCFS-3 low NO<sub>x</sub> combustion system for tangentially fired boilers. The project provided evaluations of the performance of this system with low-to-medium volatile coals typically burned in the Northeast, including some with high slagging potential. Also assessed were the performance achievable with a complete windbox replacement and the use of dynamic classifiers.

The effectiveness of Low-NO<sub>x</sub> Concentric Firing System Level 3 (LNCFS-3) burner retrofit in reducing NO<sub>x</sub> emissions while maintaining high combustion efficiency and acceptable fly ash loss-on-ignition (LOI) was evaluated in the NYSEG Milliken Units 1 and 2 tangentially-fired boilers. The results of this low sulfur test program can be found in detail in the study entitled "Unit 1 LNCFS Level 3 and Unit 2 Baseline Test Program Results" prepared by CONSOL, and dated December 1996. This study provides a detailed comparison of Milliken Unit 1 & 2 NO<sub>x</sub> emissions, defines the Unit 2 and Unit 1 Post-Retrofit Diagnostic Tests, and provides results and discussions of the Long-term, Validation and Performance Testing. The complete report can be obtained by contacting NYSEG. A summary of the LNCFS demonstration program is provided below.

Unit 2 baseline test results were used to assess the NO<sub>x</sub> emissions reduction achieved by Unit 1 LNCFS-3 retrofit while maintaining high combustion efficiency and acceptable fly ash LOI. Milliken Units 1 and 2 are rated at 150 MW net each. The coal used was a high volatile (37%-38% dry volatile matter), medium sulfur (1.6%-2.0% dry sulfur) Pittsburgh Seam coal.

Pre-retrofit data showed that NO<sub>x</sub> emissions differences between the two units were small. The original plan was to conduct baseline and post-retrofit testing on the same unit. However, there was not sufficient time to conduct Unit 1 baseline testing prior to its retrofit. Consequently, the option of conducting baseline testing on Unit 2 and post-retrofit testing on Unit 1 to evaluate the effectiveness of the low-NO<sub>x</sub> burner retrofit was adopted. Unit 2 retrofit was scheduled approximately one year after that of Unit 1. A comparison of Units 1 and 2 NO<sub>x</sub> emissions was conducted using data from short-term tests (1-3 hours) and long-term measurements (60 days).

Four test programs were conducted on each unit, including diagnostic, long-term, validation, and performance evaluation. The diagnostic tests were short-term (2-4 hours) statistically designed parametric tests in which the effects of selected process variables on NO<sub>x</sub> emissions and fly ash Loss-on-Ignition (LOI) were evaluated. The long-term tests

involved 60-70 days of data collection to estimate the achievable annual NO<sub>x</sub> emissions. The validation tests were similar to the diagnostic tests in which the effects of selected variables were re-evaluated following the long-term tests. The performance tests evaluated the impact of the LNCFS-3 burner retrofit on boiler performance.

Limited success was achieved in reproducing the diagnostic test results during the validation test programs because of the difficulty in reproducing the diagnostic test conditions. For example, control of overfire air during the LNCFS-3 diagnostic tests was limited, producing full boiler load LOI above 4%. The limitations were relaxed during the validation tests, producing 0.7%-1.7% (absolute) lower LOI, with a minor effect on NO<sub>x</sub> emissions.

At full boiler load (145-150 MW) and 3.0%-3.5% economizer O<sub>2</sub>, the LNCFS-3 burner lowered NO<sub>x</sub> emissions from a baseline of 0.64 lb/MM Btu to 0.39 lb/MM Btu (39% reduction). At 80-90 MW boiler load and 4.3%-5.0% economizer O<sub>2</sub> the LNCFS-3 burner lowered NO<sub>x</sub> emissions from a baseline of 0.58 lb/MM Btu to 0.41 lb/MM Btu (29% reduction). With the LNCFS-3 burner, fly ash LOI below 4% was maintained, and CO emissions did not increase.

The boiler efficiency was 89.3%-89.6% for baseline and 88.3%-88.5% for LNCFS-3. A lower LNCFS-3 boiler efficiency than baseline was attributed to higher post-retrofit flue gas O<sub>2</sub> and higher stack temperatures which accompanied the air heater retrofit. When LNCFS-3 and baseline were compared at similar flue gas temperatures and compositions, estimated LNCFS-3 boiler efficiency was 0.2% (absolute) higher than baseline.

## **UNIT 2 BASELINE DIAGNOSTIC TEST PROGRAM**

The Milliken Unit 2 baseline diagnostic test program, conducted during December 6-15, 1993, evaluated the effects of boiler load, excess O<sub>2</sub>, coal air flow, burner tilt, and reduced load mill patterns on NO<sub>x</sub> emissions and LOI. The following conclusions were reached:

- Both NO<sub>x</sub> and LOI results showed good reproducibility. Uncertainties at 95% confidence were  $\pm 0.016$  lb NO<sub>x</sub>/MM Btu and  $\pm 0.30\%$  LOI. NO<sub>2</sub> was not measured, and reported NO<sub>x</sub> measurements were the sum of both NO and NO<sub>2</sub>.
- Changing fuel air damper position had a significant effect on LOI and a minor effect on NO<sub>x</sub> emissions. Increasing fuel air damper position from 2 to 4 increased LOI by 0.5%. The minimum and maximum fuel air damper positions were 1 and 5, respectively.
- Variation in burner tilt affected NO<sub>x</sub> emissions, but not LOI. Changing burner tilt from  $\pm 15^\circ$  to  $0^\circ$  increased NO<sub>x</sub> emissions by 0.04 lb/MM Btu.

- At reduced boiler loads (110 MW and lower), taking the top burner elevation out of service reduced NO<sub>x</sub> emissions, but made it difficult to maintain steam temperatures.
- Higher excess O<sub>2</sub> levels (measured at economizer outlet) increased NO<sub>x</sub> emissions and reduced LOI. The results showed that the impact of excess air on NO<sub>x</sub> emissions was reduced at lower boiler loads.
- Higher boiler loads increased NO<sub>x</sub> emissions and reduced LOI at the same excess O<sub>2</sub> level.
- Lower NO<sub>x</sub> emissions corresponded to higher LOI. Predictive correlations for NO<sub>x</sub> emissions and LOI were derived:

$$1b \text{ NO}_x / \text{MM Btu} = 0.34 - 0.036 \cdot O_2 + 0.0009 \cdot \text{MW} \cdot O_2 - 0.00017 \cdot (\text{TILT})^2 \quad r^2 = 91\%$$

$$\% \text{ LOI} = -1.2 + 9.4/O_2 + 0.25 \cdot \text{AIR} - 0.024 \cdot (\text{MW}-140) \quad r^2 = 84\%$$

where

O<sub>2</sub> is excess O<sub>2</sub> measured at the economizer outlet, MW is boiler load in MW net, TILT is burner tilt in degrees, and AIR is coal air damper position.

- The short-term, baseline tests indicated that NO<sub>x</sub> emissions could be reduced to about 0.54 lb/MM Btu at 140 MW, while maintaining salable fly ash.

## UNIT 1 POST-RETROFIT DIAGNOSTIC TEST PROGRAM

The Milliken Unit 1 post-retrofit diagnostic test program, conducted during March 22-31, 1994, evaluated the effects of boiler load, excess O<sub>2</sub>, mill classifier speed, combustion air distribution (SOFA flow, CCOFA flow and coal air flow), burner settings (burner tilt, SOFA tilt and SOFA yaw), and mill patterns on NO<sub>x</sub> emissions and LOI. The following conclusions were reached:

- The post-retrofit tests had a greater level of uncertainty in NO<sub>x</sub> emissions and about the same level of uncertainty in LOI, compared to the baseline tests. Uncertainties at 95% confidence were ± 0.027 lb NO<sub>x</sub> /MM Btu and ± 0.35% LOI.
- Gas stratification across the two ducts at the economizer outlet was minor.
- NO<sub>2</sub> concentrations measured at the economizer outlet were 1-2 ppm.
- CO variation was not considered in this study because of the low concentrations measured at the economizer outlet (9-23 ppm).
- Increasing burner tilt below the horizontal position (0°) was estimated to reduce NO<sub>x</sub> emissions by 0.007 lb/MM Btu and to reduce LOI by 0.16% per degree change at full

boiler load. The impact of burner tilt on main steam temperature limited changes in the burner tilt.

- Changes in SOFA tilt produced no significant changes in either NO<sub>x</sub> emissions or LOI. SOFA yaw changes (relative to the fuel firing angle) did not significantly change NO<sub>x</sub> emissions, and increased LOI. The effect on LOI could not be determined with certainty because SOFA yaw changes were accompanied by changes in burner tilt, and the two effects could not be separated. No significant changes in steam temperatures were detected.
- Greater air staging (air flow through SOFA and CCOFA ports) reduced NO<sub>x</sub> emissions and increased LOI. Changes in SOFA damper position had a greater effect on NO<sub>x</sub> emissions than changes in CCOFA damper position. The effect on LOI was not statistically significant when the effects of other parameters, such as burner tilt, were accounted for.
- Taking the upper elevation burners out of service reduced both NO<sub>x</sub> emissions and LOI, but the effect was greater on NO<sub>x</sub> emissions.
- Higher excess O<sub>2</sub> increased NO<sub>x</sub> emissions and reduced LOI.
- In general, higher boiler loads increased both NO<sub>x</sub> emissions and LOI.
- Higher mill classifier speeds reduced both NO<sub>x</sub> emissions and LOI, but the effect on LOI was more dramatic.
- The post-retrofit relationship between NO<sub>x</sub> and LOI was more complex than the pre-retrofit relationship because of greater sensitivity of the low NO<sub>x</sub> configuration to process variables and coal properties. Fluctuations in coal ash and/or moisture contents had a dramatic effect on LOI and a minor effect on NO<sub>x</sub> emissions.
- Predictive correlations for NO<sub>x</sub> emissions and LOI were derived:

$$\text{lb NO}_x / \text{MM Btu} = 0.12 + 0.08 * \text{O}_2 + 0.00003 * (\text{MW} - 120)^2 - \\ (\text{RPM} - 93) + 0.007 * \text{TILT} \quad r^2 = 84\%$$

$$\% \text{ LOI} = 8.1 - 1.08 * \text{O}_2 + 0.032 * (\text{MW} - 120) - \\ (\text{RPM} - 93) + 0.155 * \text{TILT} \quad r^2 = 69\%$$

where

O<sub>2</sub> is excess O<sub>2</sub> measured at the economizer outlet, MW is net MW boiler load, TILT is burner tilt in degrees from the horizontal, and RPM is mill classifier speed.



- The short-term, post-retrofit LNCFS-3 test program indicated that NO<sub>x</sub> emissions could potentially be reduced to about 0.35 lb/MM Btu at full boiler load, while maintaining salable fly ash.
- The low NO<sub>x</sub> burner retrofit reduced NO<sub>x</sub> emissions from a baseline level of 0.64 lb/MM Btu to a post-retrofit level of 0.39 lb/MM Btu, corresponding to a reduction of about 39%, while maintaining LOI below 4%. The NO<sub>x</sub> values were based on short-term test averages, subject to verification during the 51-day long-term test. NYSEG believes LNCFS-3 burner retrofit is a cost-effective technology to comply with Title IV of the 1990 Clean Air Act Amendments. To date, burner operations have been acceptable.

### **LONG-TERM TEST PROGRAM**

Long-term testing was conducted following the completion of the diagnostic test programs and involved 60-70 days of data collection to estimate the achievable annual NO<sub>x</sub> emissions. The validation tests were similar to the diagnostic tests and re-evaluated the effects of selected process variables following the completion of long-term testing. The performance evaluation tests evaluated the impact of the LNCFS-3 burner retrofit on boiler performance, including NO<sub>x</sub> and CO emissions, fly ash LOI and boiler efficiency.

The achievable annual NO<sub>x</sub> emissions were estimated using long-term (60-70 days) CEM measurements. The achievable annual NO<sub>x</sub> emissions were calculated based on 30-day rolling averages obtained from the long-term CEM data. A 30-day rolling average is obtained by averaging 30 continuous daily averages following the initial 30-day lapse and rolling the average from day to day. The daily averages were calculated from the hourly averages. Specifically:

- The achievable annual NO<sub>x</sub> emissions for Unit 2 baseline were 0.614 lb/MM Btu, with a 95% confidence level of  $\pm 0.023$  lb/MM Btu.
- The achievable annual NO<sub>x</sub> emissions for Unit 1 LNCFS-3 were 0.390 lb/MM Btu, with a 95% confidence level of  $\pm 0.003$  lb/MM Btu. That corresponded to 134 MW boiler load and 3.72% O<sub>2</sub> at the economizer outlet. The LNCFS-3 burner system achieved 36% NO<sub>x</sub> reduction. However, direct comparison of baseline and post-retrofit NO<sub>x</sub> emissions can be misleading, since the corresponding economizer O<sub>2</sub> levels were different.

### **VALIDATION TEST PROGRAM**

The validation test programs were conducted after the completion of the long-term tests. The purposes of validation tests were to re-evaluate the effects of selected operating parameters on NO<sub>x</sub> emissions and LOI and to verify the diagnostic test results. The validation test results were compared to predictions based on the correlations derived from the diagnostic test results. The test parameters for Unit 2 baseline were economizer

O<sub>2</sub> and boiler load. The test parameters for Unit 1 LNCFS-3 were economizer O<sub>2</sub>, coal fineness and boiler load. The following conclusions were reached:

- For Unit 2 baseline, satisfactory predictions were obtained for both NO<sub>x</sub> emissions and LOI at full boiler load (140-150 MW), but not at reduced boiler loads. Full boiler load differences between measurements and predictions were less than 0.03 lb NO<sub>x</sub> /MM Btu and less than 0.3% (absolute) LOI. The larger differences in reduced boiler load test results were caused by differences in mill operations.
- For Unit1 LNCFS-3, satisfactory predictions were obtained for NO<sub>x</sub> emissions at full boiler load (145-150 MW). However, predictions for NO<sub>x</sub> emissions at reduced boiler loads and all predictions for LOI (full and reduced boiler loads) were not satisfactory. At full boiler load, differences between measured and predicted NO<sub>x</sub> emissions were less than 0.036 lb/MM Btu, and measured LOI was consistently lower (0.7%-1.7% absolute) than predicted. Full boiler load differences between measurements and predictions are explained as follows. The diagnostic test conditions produced full boiler load LOI above 4% and were not repeated during the validation test program. The modified operations had a minor effect on NO<sub>x</sub> emissions and a significant effect on LOI. LOI correlations should be adjusted to account for this difference.

## **PERFORMANCE EVALUATION**

The LNCFS-3 performance evaluation included the impact of the LNCFS-3 system on NO<sub>x</sub> emissions, boiler efficiency, fly ash LOI and CO emissions. Specifically:

- At full boiler load (145-150 MW) and 3.0%-3.5% economizer O<sub>2</sub>, the LNCFS-3 system lowered NO<sub>x</sub> emissions from a baseline 0.64 lb/MM Btu to 0.39 lb/MM Btu (39% reduction). At 80-90 MW boiler load and 4.3%-5.0% economizer O<sub>2</sub>, the LNCFS-3 system lowered NO<sub>x</sub> emissions from a baseline of 0.58 lb/MM Btu to 0.41 lb/MM Btu (29% reduction).
- The boiler efficiency was 89.3%-89.6% for baseline and 88.3%-88.5% for the LNCFS-3 system. The LNCFS-3 boiler efficiency was lower than baseline because of higher post-retrofit flue gas O<sub>2</sub> levels and higher stack temperatures which accompanied the air heater retrofit. When the LNCFS-3 system and the baseline were compared at similar flue gas temperatures and compositions, the estimated LNCFS-3 boiler efficiency was 0.2% (absolute) higher than baseline.

With the LNCFS-3 system, fly ash LOI below 4% was maintained, and CO emissions did not increase.

## 8.4 MILLIKEN SNCR DEMONSTRATION

The original purpose of this program was to investigate the capability of a selective non-catalytic reduction (SNCR) technology to provide an additional reduction in NO<sub>x</sub> emissions beyond that achievable by combustion modifications alone. Naico's NOxOUT® SNCR process was to be employed utilizing various injection points within the boiler. The SNCR process was to be optimized by varying the location and number of injection points, reagent concentration and reagent feed. NYSEG planned to demonstrate the NOxOUT® process on Milliken Unit 2. The process was expected to reduce NO<sub>x</sub> emissions by more than 30% in addition to the reductions achieved by combustion modifications. Project goals included:

- Demonstration of additional NO<sub>x</sub> reductions beyond the reductions achieved by combustion modifications;
- Minimal ammonia (NH<sub>3</sub>) slip, with a goal of ~2 to 3 ppmv ammonia slip during long-term tests;
- Minimal impact on downstream equipment: heat exchanger, ESP and FGD system;
- Maintenance of marketable by-products: fly ash, gypsum, CaCl<sub>2</sub>.

The original test program was designed to provide operation and performance data to confirm the NOxOUT® technology's ability to meet regulatory requirements for new and existing utility boilers. Because the Environmental Protection Agency regulations are different for new and existing utility boilers, the data collected had to be applicable to both. Therefore, the plan included evaluating NOxOUT® nitrogen oxide emission control system data for compliance with New Source Performance Standards (NSPS) as well as the Clean Air Act Amendments of 1990 Titles I and IV. Data were to be collected to determine: (1) percent reduction of NO<sub>x</sub> achievable, (2) short-term NO<sub>x</sub> emissions, (3) 30-day rolling average NO<sub>x</sub> emissions, and (4) annual NO<sub>x</sub> emissions. The demonstration program was to be operated to comply with all applicable regulations. No test condition was to be maintained which caused a violation of air, water or solid waste permits.

Most of the process control was to be performed automatically based on data from *continuous on-line process monitors*. Continuous measurements of flow, pressure and liquid level were to be performed using standard commercial industrial process monitors. The accuracy of these monitors was to be specified during the design phase and verified during installation and shake-down. NO<sub>x</sub>, O<sub>2</sub> and CO concentrations in the flue gas stream were to be measured.

Non-continuous process control monitoring for the NOxOUT® process was to include analysis of the SNCR solution going to the boiler, analysis of SNCR concentrate delivered to the plant and measurement of ammonia in the flue gas and fly ash. Samples

of the SNCR solution were to be taken daily to measure the concentration and density to adjust process control variables. Samples of the concentrate were to be taken upon delivery to determine purity of the delivered product. The flue gas was to be manually sampled for NH<sub>3</sub> during the NOxOUT® variable testing. The physical and chemical data required for by-product sales or disposal were to be acquired during the long-term, steady-state NO<sub>x</sub> OUT® process operating period. The data were to be usable by utility or industrial boiler operators to evaluate the economics and environmental acceptability of either the disposal or the by-product sale option.

In 1995, NYSEG received information that the NOxOUT® process had been installed at Penelec's Seward Station, a unit similar to Milliken Station, and that substantial difficulty was being experienced during startup with plugging of the air preheaters. To mitigate risks to the efficient, reliable operation of Milliken Station and to avoid unnecessary duplication of efforts it was decided to use data generated by the Seward installation to satisfy the MCCTD reporting commitments for the NOxOUT® process.

As of the date of publication of this Project Performance and Economics Report details of the testing program conducted at Seward and reports of the test results had not been published. When available this information will be included in a future topical report.

## 8.5 MILLIKEN ESP UPGRADE EVALUATION

The purpose of the ESP Upgrade Evaluation program was to assess industry's ability to predict the performance of multiple simultaneous upgrades and to demonstrate the reduction in air toxics emissions realized from reducing flue gas temperatures by 10-30 °F and particulate emissions by 50%. The program included performance testing to evaluate the effectiveness of the combination of ESP upgrades in reducing particulate emissions in general, as well as fine particulate and air toxics emissions and to evaluate the added benefits of implementing these upgrades simultaneously with combustion modifications and pulverizer upgrades for NO<sub>x</sub> control. Also assessed were design aspects of the ESP including power consumption, fields, process optimization of T-R controls and final set points.

As part of NYSEG's Milliken Station Project, electrostatic precipitators (ESP) on the two 160 MW boilers were upgraded to accommodate the wet flue gas desulfurization system. Upgrades of the ESP on each unit consisted of replacement of the internals and retirement of part of the original ESP. A wide plate spacing design was provided by the ESP vendor, Belco Technologies, Inc. With a 16-inch plate spacing, the modified unit is smaller and requires less energization power.

CONSOL Inc. Research & Development conducted performance tests on the original and modified ESP's. The same coal was fired in the boiler during these tests. Results indicate that the modified ESP shows better removal efficiency than the original unit even though it has less than one-half of the collection plate area of the original ESP. The voltage:current product data indicate that the power requirement is 25% less than that of the original ESP. The results of this test program can be found in detail in the report entitled "Unit 2 Electrostatic Precipitator Performance Test Results Before and After Modification" prepared by CONSOL, and dated December 1996. Copies of the report can be obtained from NYSEG upon request.

Originally, the Unit 2 particulate control system consisted of two ESP's in series, stacked one on top of the other. Each ESP consisted of two independent sections with the gas flow separating upstream of the air heater and rejoining downstream of the final ESP. Each section had two fields energized by a total of ten transformer-rectifier (TR) sets. During the modifications, the bottom ESP was removed completely and the top one was rebuilt. The internals of the top ESP were replaced using a wide plate spacing design by Belco. An additional third field was added to the ESP. Six new computer controlled TR sets were installed replacing the originals. The physical characteristics of the old and new ESP systems are shown in the following table.

**TABLE 8.5-1  
PRECIPITATOR CHARACTERISTICS  
ORIGINAL VS. MODIFIED ESP**

	Lower ESP 1955-1958	Upper ESP 1971-1974	New ESP 1993
Date Built	1955-1958	1971-1974	1993
Plate Spacing, inches	8.75	9	16
Plate Height, feet	20	30	30
Fields	2	2	3
Field Depth, feet per field	9	9	9
Gas Velocity, fps	5.7	3.4	3.7
SCA, ft <sup>2</sup> /1000 acfm gas @ full load	150	242	175

As shown in this table, the plate spacing was increased from approximately nine inches to sixteen inches while the total number of fields decreased from four to three. The SCA at full load decreased from 392 to 175 ft<sup>2</sup> per 1,000 acfm of flue gas. Even with the reduced SCA, the new design was projected to have a higher removal efficiency because the wider plate spacing permits higher applied voltages. The effectiveness increased 80%; that is, the new effectiveness is 1.8 times the original (16 over 9). Similarly, the operating power was expected to decrease by 262 kW.

The modified Milliken Unit 2 ESP still consists of two separate, parallel sections: a south or "A" ESP and a north or "B" ESP. Gas flow is evenly split between these sections. Each side has an additional division wall that runs the length of the ESP box. The south and north sides are identical parallel precipitators with separate TR sets enclosed in a single box. Three fields on each side are individually powered by a total of six TR sets.

Testing of the original and modified ESP's was conducted by CONSOL Inc., Research & Development to document the effectiveness of the modifications. ESP inlet and outlet data were obtained for the following parameters:

- Total Particulate Matter (PM)
- Sulfur Dioxide (SO<sub>2</sub>)
- Sulfuric Acid Mist (SO<sub>3</sub>)
- Particle Size Distribution
- Flue Gas Composition (O<sub>2</sub>, CO<sub>2</sub>, N<sub>2</sub>, and H<sub>2</sub>O)
- Volumetric Flue Gas Flow Rate
- Flue Gas Temperature
- Fly Ash Resistivity at the ESP Inlet

Coal and fly ash samples were collected and analyzed. TR set primary voltage, primary current, and secondary current data were collected during the original baseline ESP performance evaluation. This information along with additional plant data was collected during the modified ESP performance evaluation. The additional plant and ESP

operating data for the modified evaluation were required for evaluation of the EPRI ESP predictive model, ESPert™.

Testing for baseline performance evaluation was conducted in April 18-20, 1994. On October 17-20, 1995, performance testing of the modified Unit 2 ESP was completed. A medium sulfur (1.8% wt % sulfur), bituminous coal was fired in the boiler during both trials. During the modified ESP field tests, data were collected for each side of the ESP separately.

The two sides of the modified ESP were treated as separate, independent units each treating one-half of the Unit 2 boiler flue gas. The baseline performance test was conducted on the total inlet/outlet flows.

Performance of the modified ESP was superior to that of the original ESP's at lower power requirement. As the particle size decreases, the performance differences disappear. The performance was calculated from the total particulate concentrations into and out of the ESP. This was used to calculate the penetration. In general, penetration is independent of the absolute concentration for a given size. Penetration is:

$$\text{Penetration} = 100\% - \text{Removal}$$

Penetrations for the <10 µm and <2.5 µm fractions were calculated using the daily particle size data.

The coal and fly ash properties did not change appreciably between the baseline test and the performance test on the modified ESP. Inlet fly ash particulate sizes also were similar. Coal sulfur levels, ash concentrations and higher heating values were similar on a dry basis. Fly ash carbon content was slightly higher in the baseline test - 4.04 wt % versus 2.40 wt %. Fly ash resistivities were also similar. Based on these data, the coal and fly ash properties were identical for both performance tests. Inlet solid concentrations were also similar for both test series. The inlet loading varied between 2.2 and 2.9 gr/dscf.

Results of the performance testing showed that the overall removal improved for the modified ESP. The average penetration before modification was 0.22%, versus 0.12% after. For the <10 µm fraction and the < 2.5 µm fraction, the differences appear minimal. Penetration of these fractions is dominated by the finest particulate fractions. The very fine particulate is only a small portion of the total inlet sample and thus, small variations dominate the results. For example, the < 2.5 µm fraction is less than 5% of the inlet material. For the particulate fraction <10µm, the penetration is the same for both performance tests at 0.02%.

V-I (voltage-current product) demand is directly related to the power requirement. The modified ESP has 75% of the V-I demand of the original ESP's. The new TR sets show a

higher primary voltage, as seen in tables 8.5-1 and 8.5-2. The primary current is about the same; thus, since the modified area is about one-half that of the original ESP, the secondary voltage is about double that for the original ESP's with a 9-inch plate spacing. More than 50% of the V-I requirement is associated with the third field on each side of the modified ESP.

**TABLE 8.5-2  
APRIL 1994 ESP TR-SET PRIMARY SIDE CONDITIONS  
MILLIKEN UNIT 2 ESP BASELINE TESTS**

TR-Set Designation	17-Apr-94		18-Apr-94		19-apr-94	
	Primary Voltage, Volt	Primary Current, Amp	Primary Voltage, Volt	Primary Current, Amp	Primary Voltage, Volt	Primary Current, Amp
TR-2A3-2S	260	78.0	261	78.5	260	78.5
TR-2A3-1	245	130.0	255	135.0	250	135.0
TR-2A3-2N	235	63.0	240	63.0	235	63.0
TR-2B4-2S	245	63.0	245	62.0	245	62.0
TR-2B4-1	290	140.0	290	140.0	290	140.0
TR-2B4-2N	240	71.0	240	71.0	240	61.0
TR-2A1-2	280	142.0	280	142.0	280	142.0
TR-2B2-2	290	135.0	290	136.0	285	135.0
TR-2B2-1	290	140.0	290	140.0	290	140.0
TR-2A1-1	270	132.0	275	133.0	275	134.0

**TABLE 8.5-3  
OCTOBER 1995 ESP TR-SET PRIMARY SIDE CONDITIONS  
MILLIKEN UNIT 2 MODIFIED ESP TESTS  
(averages of readings recorded during the performance tests)**

TR-Set Designation	17-Oct-95		18-Oct-95		19-Oct-95		20-Oct-95	
	Primary Voltage, Volt	Primary Current, Amp	Primary Voltage, Volt	Primary Current, Amp	Primary Voltage, Volt	Primary Current, Amp	Primary Voltage, Volt	Primary Current, Amp
TR-1B1	298	38.2	290	34.8	294	36.6	292	35.7
TR-2B2	388	82.9	397	86.5	389	82.8	390	83.3
TR-2B3	440	125.3	421	120.9	442	128.1	441	132.6
TR-2A1	272	36.6	265	33.0	270	35.0	268	34.8
TR-2A2	434	103.1	425	105.0	431	102.8	429	104.1
TR-2A3	471	150.6	468	151.6	473	151.6	473	153.8

The modified ESP performs better than the original unit at a lower operating (power) cost. Overall penetration for the modified ESP is about half that of the original ESP. This improvement occurs with a 25% savings in V-I power requirements. The modified ESP has a smaller plant footprint with fewer internals and a smaller SCA. Total internal plate area is less than one-half that of the original ESP's, tending to lower the capital cost.



## 8.6 EVALUATION OF ESPert™ ESP MODEL

NYSEG's Milliken Station was extensively modified to accommodate a wet scrubber, flue gas desulfurization system. Modifications included upgrading the ESP's on both units. Prior to the modifications the Unit 2 particulate control consisted of two ESP's in series, stacked one on top of the other. The bottom unit was removed completely while the top unit was rebuilt and an additional, third field added. The internals of the top ESP were replaced using a wide plate spacing design by Belco Technologies Corp. New, computer controlled TR sets were also installed. The plate spacing was increased from approximately nine inches to sixteen inches while the total number of fields decreased from four to three. The SCA at full load decreased from 392 to 175 ft<sup>2</sup> per 1,000 acfm of flue gas. The efficiency of the original ESP was 99.43% on a 1.54 wt % sulfur coal. For a 3.2 wt % sulfur coal, the efficiency was 99.65%. After the retrofit, the efficiency increased to 99.9% for a 1.75% sulfur coal.

ESPert™, an ESP model developed by Peter Gelfand of P. Gelfand Associates under the auspices of EPRI was evaluated by comparing the predicted performance with actual ESP performance measured at Milliken Station Unit 2. The ESPert™ computer model was produced from algorithms developed by the Southern Research Institute. Version 4.2 was used, in the DOS operating system on a PC compatible, Intel 486 PC.

In October 1995, the performance of the Unit 2 ESP was evaluated while firing a medium sulfur (1.75 wt % sulfur), bituminous coal in the boiler. Field tests were conducted to collect inlet and outlet particulate concentrations and flue gas data for each side of the ESP separately. For comparison of the results, the two sides of the ESP were treated as separate, independent units each treating one-half of the flue gas exiting Unit 2.

Data required by the ESPert™ model were obtained from three sources: the field test report of the ESP performance; the Milliken Station data logger; and data provided by NYSEG personnel. The field report details the testing procedure for the Unit 2 ESP and the results of the performance tests. The Milliken data logger provided general operating conditions and an indication of boiler and ESP operating stability during the field test. NYSEG personnel provided station and ESP design specifications, and air load voltage-current (V-I) data for the V-I curves required for the ESP performance calculation.

The ESP field report discusses the test methods and results of duplicate testing of the Unit 2 ESP. The north and south sides were tested separately and were individually compared with their respective ESPert™ predictions. Inlet and exit data were obtained from the field report for several parameters. The following parameters are included in the ESPert™ evaluation:

- Total particulate matter (PM)
- Particle size distribution
- Flue gas composition (O<sub>2</sub> and H<sub>2</sub>O)
- Volumetric flue gas flow rate

Flue gas temperature  
Actual fly ash resistivity at the Inlet

Coal and ash samples were collected during the field test and analyzed. Analyses of the daily composites of the coal samples were consistent within analytical error and their averages were used for the ESPert™ calculations. The fly ash analyses also were averaged.

Four sets of inlet and outlet particle size data were collected during the field test, two sets for each side of the Unit 2 ESP. The calculated  $D_{50}$  and cumulative weight percents were plotted on Rosin-Rammler coordinates to obtain an estimate of the performance for the minus 10  $\mu\text{m}$  and minus 2.5  $\mu\text{m}$  fractions. The minus 10  $\mu\text{m}$  and minus 2.5  $\mu\text{m}$  fractions were estimated directly from the data with no smoothing or curve fitting.

During the field test program, five trials collecting gas flow, temperature and total particulate data were conducted on the north-side ESP and three on the south. Of these, North #1, #3 and #4 and all three south trials sampled the inlet and outlet streams simultaneously. These six trials are compared with ESP performance predicted by the model. Total particulate concentrations into and out of one side of the ESP were collected as part of the procedure for each trial. This was used to calculate the penetration. Penetrations for the minus 10  $\mu\text{m}$  and minus 2.5  $\mu\text{m}$  fractions were calculated using the daily particle size data. The size test provided the size distribution for the total particulate concentrations conducted on the same day.

ESPert™ used the sample  $D_{50}$  and the log-normal standard deviation of the distribution calculated from the inlet particle size data to generate a size distribution for its calculation procedures. P. Gelfand Associates recommended having the program generate 21 size fractions rather than using actual data. This was recommended because of the way ESPert™ treats this data internally. Gelfand recommended values for several other parameters.

For the actual ash resistivity, an average of the results of the four days of testing was used. The actual ash resistivities (AR) were consistent. These resistivities lie between the curves predicted from the two resistivity algorithms in ESPert™. The algorithms that include  $\text{SO}_3$  effects are referred to as Model 1 and Model 2. The measured resistivities agree closely with the values predicted by Model 1, showing a similar, slight increase with increasing temperature. Model 2 resistivities are much lower. No bias was evident in the horizontal position of the sample port used for obtaining the resistivity value. It should be noted that ESPert™ recommends using the Model 2 resistivity algorithm for predicting ESP performance in the event actual resistivity measurements are unavailable.

ESPert™ requires operating or full load V-I data to predict operating behavior. Air load V-I data were used since full load data could not be obtained without requesting a

variance. These values were entered into ESPert™ as full load data according to Gelfand's recommendation.

The test results were compared with the removals of fly ash predicted by ESPert™. Air load V-I values were substituted for full load data. Otherwise, the normal procedure was followed. Both algorithms used to predict ash resistivity in the ESP model and the AR were explored in this evaluation.

ESPert™ consistently predicted lower efficiencies (higher penetrations) than measured at the Milliken ESP. Overall, predicted penetrations using the Model 2 resistivity agreed with those predicted using the AR but were six to seven times higher than measured penetrations. Using the Model 1 resistivity, the predicted penetrations were two to four times higher than those predicted by the AR or Model 2 resistivities. While Model 1 closely predicts the observed resistivity, it does not predict the ESP efficiencies as well as Model 2. For the finer fractions, the predicted penetrations are closer to the observed values. The reasons for this trend are not known.

Similarly, for the minus 10 µm fraction, the Model 1 penetration prediction was the least accurate. The AR and Model 2 penetrations were 4.5 to 6 times the average measured value, while the Model 1 predictions were again 2 to 4 times higher than the other predictions. Thus, the Model 1 predictions were 10 to 22 times higher than the average measured penetration.

The predicted penetrations of the minus 2.5 µm fraction for the AR and Model 2 resistivities were within the experimental error from the average measured value. However, they were consistently higher than the measured penetrations varying between 1.2 and 2 times higher, suggesting some potential bias. Again the Model 1 value was much higher, 3 to 5 times the measured penetrations. While the amount of material in this fraction is very small, it appears that the ESPert™ model adequately predicts this fraction.

Two of the possible reasons for this high estimate of penetration are the design basis of ESPert™ and the difference between operating and air load V-I curves. The ESPert™ model was developed using data from ESP's with a closer, predominately 9-inch plate spacing. This may explain in part the reason for its overestimation of penetration. A second possibility is that the operating V-I curves are significantly different from the air curves used in these predictions. While checking the first hypothesis was beyond the scope of the demonstration project, the second possibility was examined.

The V-I curves were replotted including the V-I data collected during the test runs. The lead TR set on each side of the ESP displays a significant shift in the ESP voltage for a given primary voltage. The ESP current also decreases for a given ESP voltage. For the other four TR sets, the differences between the air load curve and operating data points are small. Revised correlations were plotted that pass through the operating point but

have the same slope (or power) as the original correlation. These new correlation coefficients were inserted into the ESPert™ model.

Sneakage and the velocity sigma are two other ESPert™ variables that affect the agreement between the measured penetrations and predicted values. These variables affect all particle sizes. These were changed in combination with the V-I adjustment. Default values for sneakage and the velocity sigma are 0.05 and 0.15. The default values were reduced to 0.03 and 0.07, respectively. These adjustments represent a considerable improvement in the amount of sneakage and the velocity/temperature distribution across the ESP inlet.

These adjustments were applied to two of the runs, and the predicted penetrations plotted. The predictions were compared with the average penetration result from all six runs. The average measured penetration, original prediction, and four adjusted predictions -- V-I adjustment alone and combined with adjustments for sneakage, velocity and both sneakage and velocity -- were plotted for the total particulate, the minus 10 µm fraction and the minus 2.5 µm fraction.

Adjusting for the V-I correction accounted for about 40% of the model's over-prediction of penetration (compared to test measurements) of the total particulate and the minus 10 µm fraction. The sneakage and velocity sigma adjustments accounted for another 10% of the over-prediction. Applying these corrections to the minus 2.5 µm fraction, the predicted values closely approximated the average measured penetrations. For one run, the revised prediction for the minus 2.5 µm values was less than the measured values.

The apparent trend to predict higher removals for the smaller particles could be an artifact of the methodology used internally to create the size distribution. A log-normal curve is used to approximate the ESP inlet size data. The size data are not linear on a log-normal plot below 2.5 µm. Most of the minus 2.5 µm fraction appears to be very small, causing ESPert™ to over estimate the removal of this fraction. Thus, the apparent agreement with this fraction may be just a coincidence.

It appears that ESPert™ under predicts the improvement of the 16-inch plate spacing and predicts higher removals of the finest material than was observed. These predictions were developed using the AR for the resistivity value, but the Model 2 resistivity predictions were similar.

Overall, the ESPert™ model under predicts the removals of the larger fractions at Milliken Station resulting in higher predicted penetrations than observed at Milliken. These differences are greater than the error limits of the original data Southern Research Institute used for developing the algorithms. For small size fractions, the predicted penetrations are also over estimated, but are within the accuracy of the original data.

ESPert™ provides the option of diagnosing the performance of individual TR sets. Diagnostic reports were created for all six runs discussed above for the AR, Model 1 and

Model 2 resistivities. The same messages were often repeated, which is expected since the data sets are very similar. They often repeated depending upon the position of the individual TR set. Some difference was noted between resistivity models.

For TR Set 1, "Low ESP Current; Increased Resistivity" was produced for every Model 2 run, while the AR and Model 1 resistivities were "In Predicted Range". The Model 2 runs also included other messages as listed below:

- Failure of Automatic Voltage Control, False Detection of Sparks/Arcs
- Reduced Clearances
- Dust Build-Up on Collecting Electrode
- High Levels of Carbon in Fly-Ash
- Air In-Leakage into ESP Casing
- Air In-Leakage into Hopper, and
- Boiler Tube Leaks.

For the second TR set, all of the north runs and the Model 2 south runs were "In Predicted Range", but the AR and Model 1 runs had predicted current problems. The diagnostic messages for these cases on the south-side of the ESP said "High ESP Current Detected" and "Sparking Rate High, Return AVC".

TR Set 3 had only one report: "Defective Limit Circuit / SCR Shorted". This was displayed for every run and for each resistivity.

The ESP appeared to be operating normally with no indication of any problems. The on-site Belco representative also stated that the operation was normal. No indication of problems with any of the units was observed and the spark rate was low. Thus, the diagnostics generated by the model did not match the operating experience. Again this may be a result of trying to extend the results from ESP's with a narrower plate spacing to the 16-inch spacing present in the Milliken ESP.

Predictions of ESP penetration using the ESPert™ model were high for an ESP with 16-inch plate spacing firing a medium sulfur bituminous coal. The resistivity estimates for the Model 1 method were close to the actual measurements, but provided much worse estimates of ESP effectiveness than did Model 2's resistivity. Model 2's estimate for resistivity was much lower than the measured value, but the effectiveness estimates were identical.

The Milliken Unit 2 ESP has wider plate spacing (16 inches) than the units that formed the basis for Southern Research Institute's original algorithms for which the widest spacing was 12 inches and most of the data were for ESP's with 9-inch plate spacing. While it is not known how this might affect the results, it appears that the algorithms in ESPert™ underestimate the operating conditions -- secondary voltage and current -- and therefore underestimate the performance. Additional data from ESP's with wide plate spacing should be incorporated into the ESPert™ model to expand its capabilities.

Air load curves should not be used to predict the operating point for a TR set with high dust loading. For both sides of the ESP, TR Set 1 exhibited full load secondary operating current and voltage that were much higher than the air load curves. Empirical adjustment of the air load curves to account for this shift, improved the estimates of the ESP effectiveness.

The evaluation showed that the ESP model significantly under-predicted the performance of the Milliken ESP when firing a medium sulfur bituminous coal. Corrections to the ESPert™ model improved the prediction but could not fully resolve the differences. The model appears unable to predict the effect of the wide plate spacing adequately. Diagnostic messages confirmed that the operating conditions for this ESP were outside the range expected by ESPert™. Additional tests with other coals should be undertaken to define the effects of wide plate spacing.

## 8.7 S-H-U FLUE GAS DESULFURIZATION PROCESS EVALUATION

The objective of this program was to provide the U.S. utility industry with an independent evaluation of the Saarberg-Hölter Umwelttechnik (SHU) cocurrent / countercurrent, formic acid enhanced wet limestone flue gas desulfurization process, including associated system components such as the mist eliminator/wet stack and materials of construction. This program evaluated absorber module chemistry for limestone grind, formic acid concentration, and variations in recycle slurry operation relative to SO<sub>2</sub> removal, L/G ratio, pressure drop, formate loss, oxidation air utilization and gypsum and chloride brine quality.

The SHU technology was expected to reduce SO<sub>2</sub> emissions by at least 95%. Project goals included:

- Demonstration of up to 98% SO<sub>2</sub> removal efficiency while burning high-sulfur coal;
- Production of marketable commercial grade gypsum and calcium chloride by-products to minimize solid waste disposal;
- Zero waste water discharge;
- Space-saving design;
- Maintenance of station efficiency using a low-power-consumption absorber system.

In the SHU FGD process, a formic acid-buffered limestone/gypsum slurry reacts with and removes SO<sub>2</sub> from the flue gas. Flue gas from the boilers is discharged through new induced draft fans which are required to overcome the pressure loss of the ductwork, absorber, and new wet stack flues. From the induced draft fans, gas flows to the absorber, where SO<sub>2</sub> is removed. Flue gas enters at the top of the cocurrent section and is contacted with a limestone/gypsum slurry spray. Slurry is introduced by spray nozzles at four separate levels in the cocurrent section of the absorber. Next, flue gas passes through the countercurrent section where it is contacted with slurry from spray nozzles at three separate levels. The gas then passes through a two-stage mist eliminator which removes entrained water droplets before the gas is discharged via the new stack flues to the atmosphere. The absorber design incorporates a split-module absorber. Units 1 and 2 are designed to operate independently so that the flue gas from each boiler can be separately treated and discharged and gypsum dewatering can operate independently for each unit. The flue gas inlet ductwork is cross-connected so that, at low boiler loads, the flue gas from both boilers can be treated in a single absorber module.

Slurry in the absorber sump contains a small concentration of formic acid and is continuously pumped to the absorber spray nozzles. Each spray level has one dedicated pump. The pumps operate at constant flow. Pumps can be taken off line when less slurry is needed (at low load, for example) or to suit operating conditions. The use of formic

acid in the SHU design permits low-pH absorption of SO<sub>2</sub> and reduces the potential for scaling and plugging. This creates a stable system that can accommodate rapid changes in inlet SO<sub>2</sub> mass loading without affecting absorber performance.

The absorber sump acts as a back-mixed reactor in which the product of absorption (bisulfite) is oxidized to sulfate (which precipitates as gypsum). Oxidation also occurs in the absorber due to oxygen in the flue gas. Slurry in the absorber sump contains approximately 12% solids, of which >95% is gypsum; this provides seed crystals for the formation of gypsum particles, which reduces uncontrolled growth on absorber internals. Air is injected into the absorber sumps by oxidation air blowers. Side-mounted agitators provide thorough mixing of air and slurry and help prevent gypsum crystals from settling to the bottom.

Gypsum slurry is pumped from the absorber sump to the gypsum dewatering system, where it is processed into wallboard-grade gypsum. Approximately 25 tons/hr of gypsum cake (90% solids by weight) are produced at full station capacity when burning 3% sulfur coal. The process is designed to produce gypsum of consistent quality regardless of the plant load or flue gas sulfur concentration. Process liquor from the dewatering system is used for reagent preparation.

Blowdown treatment is performed to purge absorbed chloride from the slurry system and maintain zero waste water discharge. Clarified water is pumped to a basin where it is chemically and mechanically treated to remove metals and suspended solids. The treated water is either discharged or pumped to a brine concentrator which produces a concentrated calcium chloride solution. This solution can be sold as-is or mixed with bottom ash to make an anti-slip material. It can also be used as a dust suppressant depending upon the purchaser's requirement. Distilled water from the brine concentrator is returned to the FGD system.

Limestone from the storage pile is fed to the wet ball mill for size reduction. Clarified water from the gypsum dewatering system is used for limestone grinding and dilution. Limestone slurry is added to the absorber in direct proportion to the SO<sub>2</sub> mass loading by regulating the limestone slurry control valve located in the limestone slurry loop near the absorber.

After a start-up and shakedown period, a parametric testing program was conducted on Unit 2 to define the performance limits of the SHU FGD system while Unit 1 continued to run at the design operating conditions to serve as a baseline for comparison to Unit 2 and to serve as a long-term test.

The plant design is based on a nominal coal sulfur content of 3.2 wt %. Testing was conducted with three different coals with sulfur content varying over a range of 1.6 to 4.0 wt %, referred to as lower sulfur coal, design coal, and higher sulfur coal.



## LOW SULFUR COAL TESTING AND EVALUATION

The low sulfur (1.6% S) coal parametric tests were conducted on Milliken Station Unit No. 2 from October 11 to November 21, 1995. The objectives of the 1.6% sulfur coal test program were:

- To demonstrate the effect of recycle slurry formic acid concentration on SO<sub>2</sub> removal and absorber operability.
- To determine the mass transfer coefficients for the cocurrent and countercurrent sections of the absorber.
- To evaluate the effect of high gas velocity absorber operation on SO<sub>2</sub> removal.
- To determine the effect of limestone grind size on SO<sub>2</sub> removal.

For the parametric testing the same coal was fed to both boilers. Load was not a variable in the parametric tests; the test plan was designed for full load on Unit 2 for all tests. Occasionally, when load demand required that Unit 2 load be reduced, testing was suspended until Unit 2 full load was restored and the FGD system chemistry reached equilibrium. The absorber slurry chloride content was not a test variable. The target chloride level was 40,000 ppm Cl<sup>-</sup> by wt; however, during the 1.6% sulfur tests, it varied between 27,000 and 64,000 ppm.

The process is designed to achieve limestone utilization of 95% to 98% and to produce a salable gypsum byproduct. The normal control scheme is to adjust the fresh limestone slurry feed rate based on the total SO<sub>2</sub> mass flow in the flue gas at the absorber inlet; trim control is based on absorber slurry pH, which prevents excursions during major process changes such as load swings. During the parametric testing program, the pH control loop was used to maintain a constant absorber chemistry despite widely changing SO<sub>2</sub> removals. The pH set point was 4.2. During the zero formic acid tests, six additional tests were performed at a pH of 5.0 to determine the effect of pH on SO<sub>2</sub> removal.

The parametric test plan was designed to study the effect of formic acid concentration, L/G ratio, and mass transfer on absorber performance. Ideally, all the parametric design should be randomized, but the large absorber sump capacity (270,000 gal) made it impractical to frequently change the formic acid concentration. Therefore, the program was set up in blocks of tests in which the formic acid concentration was kept constant for 4 to 25 days. The test blocks were conducted in order of increasing formic acid concentration. The nominal formic acid concentrations tested were 0 ppm, 400 ppm and 800 ppm; the average measured formic acid concentrations for these test blocks were 58 ppm, 462 ppm, and 981 ppm, respectively. The zero formic acid concentration tests were performed first. Before the test program began, the formic acid feed rate was reduced to zero by shutting off the formic acid metering pump seven days before the start of testing.

L/G variation was achieved by varying the number of spray headers in operation at constant flue gas flow. The spray headers operate in an on/off mode, i.e., there is no flow control on the headers. There are no flow indicators installed on any of the headers. The design flow rates were used to calculate the L/G ratios. Mass transfer was calculated for the cocurrent and countercurrent sections using the design flow values. There are four cocurrent spray headers and three countercurrent spray headers in each absorber module. To protect the absorber from high flue gas temperature, at least one of the top two headers on the cocurrent side must be operating at all times. Each of the possible combinations of the number of spray headers in operation was tested with and without formic acid; each test was performed twice. For each combination, the upper-most headers in either section were used. The results from tests using no countercurrent sprays were used to calculate the mass transfer in the cocurrent section. By comparing these results with results from tests in which countercurrent sprays were operating, the mass transfer in the countercurrent section was calculated.

The SHU absorber design calls for different limestone grind sizes depending upon whether or not formic acid is used. Without formic acid additive, the design limestone grind size is 90% - 325 mesh; with formic acid additive the design calls for 90% -170 mesh. The parametric tests were performed using the design limestone grind sizes. For comparison purposes, three tests were performed using 90% -170 mesh without formic acid and six tests were performed using 90% - 325 mesh with formic acid.

The following are the major conclusions of the 1.6% sulfur coal test program:

### **SO<sub>2</sub> Removal**

- SO<sub>2</sub> removal ranged from 30% using only two spray headers without additive to 98% using all seven spray headers with formic acid (nominally 800 ppm).
- The maximum SO<sub>2</sub> removal was achieved when operating with three counter current spray headers and four or three cocurrent spray headers in the 800 ppm formic acid tests. The removals were 97.8%, 98.0%, 98.1%, and 98.3%, averaging 98.1 ± 0.7% (95% confidence interval of ± 0.7% (absolute)).
- SO<sub>2</sub> removals were plotted for each test level of formic acid as a function of total L/G, based on the design slurry flow rate to the headers. As expected, SO<sub>2</sub> removals increased with increasing L/G. When the results were separated based on the number of countercurrent headers operating a significant difference in SO<sub>2</sub> removals occurred for the same L/G depending upon the number of countercurrent headers in use. In general, the data show that more SO<sub>2</sub> removal is achieved when a higher percentage of the total slurry is sprayed in the countercurrent section.
- The effect of countercurrent L/G on SO<sub>2</sub> removal was significant with and without the use of formic acid, but the effect diminished with increasing formic acid concentration. In the 400 ppm formic acid tests, the removal was 49% to 67% with no countercurrent

headers operating and 81% to 96% with one to three countercurrent headers operating. In the 800 ppm formic acid tests, the removal was 55% to 71% without countercurrent headers and 95% to 98% with one to three countercurrent headers operating. These were nominal formic acid concentrations; the measured formic acid concentrations were somewhat higher than the nominal values.

- SO<sub>2</sub> removal was increased significantly by formic acid. For example, using five spray headers, SO<sub>2</sub> removal averaged 82% without formic acid and 97% with 800 ppm formic acid. SO<sub>2</sub> removal was plotted as a function of the measured formic acid concentration in the absorber slurry for four, three, two, and one cocurrent headers, respectively. The data in each figure are grouped according to the number of countercurrent spray headers operating. The figures show that formic acid causes the SO<sub>2</sub> removal curves to converge. The sulfur reduction in the 400 ppm formic acid tests was significantly greater than in tests without formic acid; the removals in the 800 ppm tests were greater than those at 400 ppm, but the difference was not as great as the difference between 400 and 0 ppm. In general, the curves show a tendency to level off with increasing formic acid concentration, which suggests that concentrations of formic acid higher than those tested would produce diminishingly smaller improvements in SO<sub>2</sub> removal.
- Nine tests were performed using an alternate limestone grind size. Higher SO<sub>2</sub> removal was observed using the finer grind (90%-325 mesh) limestone than with the coarser grind (90% - 170 mesh) limestone. The average difference in SO<sub>2</sub> removal between the two grind sizes was 2.6 percent (absolute). The effect was greatest at the intermediate formic acid concentration.
- SO<sub>2</sub> removal during the high velocity tests ranged from 90.8% to 98.4%. These tests were performed at a nominal 800 ppm formic acid concentration, with a minimum of 2 cocurrent and 4 total headers in operation. The gas velocity in the cocurrent section was 30 to 33 ft/sec, which is greater than the design velocity of 20 ft/sec. When compared on an equivalent L/G basis, more SO<sub>2</sub> was removed during the high velocity tests than during the design velocity tests. For example, SO<sub>2</sub> removal averaged 95% at 94 gal/kacf in the design velocity tests and 97% at 89 gal/kacf in the high velocity tests. This occurred despite the fact that high velocity operation reduced the gas residence time in the absorber by about 50% compared to the design velocity residence time.

### **Pressure Drop**

- The pressure drop across the absorber was a function of the number of countercurrent spray headers operating. The average effect of each countercurrent header was to increase the pressure drop by 0.45 inches in the design flow tests and 0.64 inches in the high velocity tests. The cocurrent spray headers had no significant effect on the pressure drop.

## Mass Transfer

- Mass transfer increased with increasing L/G, but the effect was not always a linear function of L/G.
- The mass transfer in the cocurrent section of the SHU absorber increased with increasing L/G. The fourth (bottom) cocurrent header had less effect on mass transfer than the first three, especially at high formic acid concentration. The results suggest that when using 1.6% sulfur coal, the bottom cocurrent header may not be necessary, especially when formic acid additive is used.
- In the SHU absorber, the gas is scrubbed in the cocurrent section before entering the countercurrent section. The additional mass transfer which took place in the countercurrent section increased with increasing L/G. When cocurrent L/G was held constant, the relationship between mass transfer and countercurrent L/G was less than first order.
- Formic acid increased the mass transfer; however, the effect diminished with increasing formic acid concentration. At constant co- and countercurrent L/G, the effect of formic acid on mass transfer, in general, was not linear. Formic acid concentration had a stronger impact on mass transfer when countercurrent headers were used.
- Mass transfer during the high gas velocity tests was greater than in the design velocity tests at similar L/G.

## Other Considerations

**Constant process parameters.** The test plan required that process parameters that were not test variables be held constant. In the majority of cases this was possible, but two which varied were the inlet SO<sub>2</sub> concentration (due to coal sulfur variability) and the chloride content in the absorber slurry.

The inlet SO<sub>2</sub> concentration slowly decreased over the 42-day test period. During the tests without formic acid the inlet SO<sub>2</sub> averaged 1000 ppm; the average decreased to 970 ppm and 879 ppm SO<sub>2</sub> during the 400 and 800 ppm formic acid tests, respectively.

The design chloride content of the absorber slurry is 40,000 ppm. The chloride concentration was measured periodically during the test period and found to range from 27,000 ppm to more than 60,000 ppm. This wide range of chloride concentrations probably did not have much effect on SO<sub>2</sub> removal because the pH was low (4.2 ± 0.25). In earlier tests performed at the High Sulfur Test Center, the effect of chloride diminished when the pH was lowered from 6.1 to 5.4; presumably, the effect would diminish even more at lower pH. No discernible effect of chloride concentration on SO<sub>2</sub> removal was

found in repeat tests. In future tests, it is recommended that chloride concentration be more tightly controlled to reduce any possible effect on liquid phase mass transfer.

Other process conditions were relatively constant throughout the tests. The pH set point was 4.2 except for the high pH tests. Except for one test, the measured pH was within  $\pm 0.25$  of the set point. For the design gas velocity tests the boiler load was  $158 \pm 2.5$  gross MWe, giving a absorber inlet gas flow of  $490 \pm 8$  kacfm. For the high velocity tests, the combined Unit 1 and Unit 2 boiler load was  $213 \pm 11$  gross MWe, giving a gas flow of  $721 \pm 35$  kacfm. The absorber inlet gas temperature averaged  $298 \pm 13^\circ$  F in the design velocity tests and  $276 \pm 7^\circ$  F in the high velocity tests.

**Power Consumption.** Actual power consumption for operating conditions tested was not measurable because the tests were only four to six hours in duration. Some equipment, such as the limestone grinding system, were not operated continuously but rather in a batch mode during one or two shifts per day. As a result, the measured station service load is not a reliable indicator of the power consumption of the FGD process.

**Gypsum Purity.** Laboratory analyses were performed on thirteen gypsum samples. They indicate that the gypsum purity was relatively constant during the test period, ranging from 96.1 to 97.8% gypsum, regardless of the operating conditions. This is an important result because it indicates that the ability to make a marketable gypsum is relatively insensitive to changes in the operating conditions.

**Process Operability.** Because these were short term tests using lower-than-design-sulfur coal, process operability was not within the scope of this phase of testing. In general, no significant absorber operability problems occurred during testing. No measurable pressure drop increase with time was observed, indicating that the mist eliminators experienced no plugging problems. The mist eliminators worked satisfactorily during the entire test period.

During these tests, the pH control loop was relied upon to keep the absorber chemistry constant despite widely changing SO<sub>2</sub> removal levels. The pH set point was 4.2; all but one of the tests were within 0.25 pH units of the set point. However, during a test without formic acid using only two headers (2,0), low SO<sub>2</sub> removal (ca. 30%) caused a rapid increase in the absorber slurry pH. The slurry pH control loop did not adjust rapidly enough to keep the pH within the desired test range and, as a result, the pH was 4.72 during that test.

**Material Balances.** Material balances were not within the scope of these tests because of the short test duration.

## **DESIGN SULFUR COAL TESTING AND EVALUATION**

At the time this Project Performance and Economics Report was published results of the Design Sulfur Coal Testing and Evaluation Program had not been reported. When available, the program results will be presented in a topical report.

## **HIGH SULFUR COAL TESTING AND EVALUATION**

At the time this Project Performance and Economics Report was published results of the High Sulfur Coal Testing and Evaluation Program had not been reported. When available, the program results will be presented in a topical report.

## **FGD SYSTEM OPERABILITY AND RELIABILITY**

The Unit 2 FGD system first became operational on January 17, 1995. The first byproduct gypsum was produced on January 21, 1995. Operation of the FGD blowdown pretreatment system began on March 21, 1995. The Unit 1 FGD system first become operational on June 20, 1995. The brine concentrator system began operation on July 20, 1995. Both units' FGD systems started up without problems and achieved the design 95% SO<sub>2</sub> removal efficiency within a few hours, with the boilers burning 1.8 - 2.2% sulfur coal. The systems have met all their process guarantees and the by-product gypsum has been uniform in quality and is sold for commercial applications. As of this report the units have run more than 30,000 hours.

Beginning with the third quarter of 1995 and running through the end of 1997 the project Technical Progress Reports included tables of summary operating data for each Unit and for the station as a whole. These tables include data on gross and net generation, station service and FGD system power consumption, availabilities, capacity factors, thermal efficiencies, NO<sub>x</sub> emissions, fly ash quality, air heater performance, precipitator performance, fuel data, FGD system performance, and wastewater treatment system performance. Some of these variables were plotted vs. time to illustrate system performance trends. Except for scheduled outages, unit availabilities held close to 100% and capacity factors generally held between 70% and 80% for the period. Unit thermal efficiencies hovered around 35% for both units. FGD system availabilities held fairly constant at close to 100%. SO<sub>2</sub> removal efficiencies for both units showed no noticeable decline over the period, holding fairly constant at about 90%, except for periods of parametric testing. FGD system power consumption did not show any significant increase over the period, indicating that the FGD system energy efficiency did not suffer noticeable deterioration. By these measures the FGD system showed no performance deterioration nor adverse impacts on unit performance over the demonstration period.

While the FGD systems have generally performed well throughout the demonstration period they have not been completely problem free. The absorbers have experienced a greater than expected deposit of solids on the absorber internals, slurry piping, and dewatering equipment. Plugging of absorber spray nozzles was evident after the first

long (6-months) running period. The plugging consisted initially of a dark-colored scale, suspected to have originated from the limestone. Subsequent plugging has been from rubber from internal turning vanes as well as scale. The nozzles were also found to be difficult to clean when plugged and subject to breakage when being cleaned. The individual hydrocyclone elements of the primary dewatering hydrocyclone plugged weekly with gypsum scale. The scale migrated from upstream and became lodged in the hydrocyclone apex. Cleaning out the elements required removal of the polypropylene element covers. Because the disassembly was required so frequently the covers cracked and developed leaks.

The deposits were partially explained by the rubber loss and lack of recycle pump and gypsum bleed pump suction screens. Because of the increase in cost, NYSEG initially chose not to install permanent suction screens, recommended by SHU, for the recycle pumps and bleed pumps. Such screens are routinely used in SHU's European installations. The plant has installed suction screens for some of the recycle pumps and bleed pumps which has greatly reduced the plugging problems in the spray nozzles and the hydrocyclones currently operate without plugging. The plant has decided to install screens for the remaining pumps. Pump suction screens should be provided for future commercial installations of the SHU process.

The units were inadvertently operated for extended periods of time at lower than design gypsum solids concentrations. This operation, at supersaturation, resulted in a lower inventory of seed crystals for the gypsum to precipitate on in the slurry and an increase in uncontrolled gypsum growth on equipment surfaces. An operating change was instituted to increase the solids in the absorber from the original 8-12% to a higher 10-14% and to not reduce the solid concentration below the operating level prior to shutdown. This has resulted in greatly improved operability of the hydrocyclones and centrifuges and has reduced the amount of plugging in the absorber spray nozzles. Operation at the higher solids concentration has lessened the problem of solids build-up. Flow modeling indicated an advantage to adding wall wedges in the cocurrent section to aid in slurry turbulence and increase contact with the flue gas. This has indeed had a positive effect, but the wedges create a site on the underneath side for deposits to accumulate. All future installations will have smaller wedges to improve this situation.

In the dual module absorber configuration all of a module's agitators must be installed along a single wall, not opposite the pump suction. This unique configuration is a difficult mixing application. The absorber agitators, as originally installed, were not adequate to maintain gypsum slurry solids in suspension, resulting in significant accumulation of solids on the floor of the absorber sump. Absorber agitators should be more thoroughly tested and more conservatively sized in future commercial installations when applied to the dual module configuration.

Although it did not impact any process guarantees, lower than expected reagent utilization was experienced during low sulfur coal testing with 0 ppm formic acid. As the reagent feed was increased to raise SO<sub>2</sub> removal efficiency, more limestone than

expected exited the system with the byproduct gypsum. An unexpected pH gradient was found between the countercurrent side of the absorber module and the cocurrent side. In the Milliken design the reagent is added through the north wall of the absorber sump. This is the countercurrent side. The gypsum bleed pumps are also located on this side. Because the absorber agitators do not uniformly mix the slurry in the sump, and because the reagent addition point is on the same side of the vessel as the gypsum bleed to dewatering, short-circuiting of limestone to the gypsum dewatering system sometimes occurs resulting in lower than expected limestone utilization when operating without formic acid. This was evident from a difference in pH between the gypsum bleed slurry and samples drawn from the co-current side recycle pumps. After the limestone addition piping was extended 4-feet inside the module to reach a more turbulent mixing area, the observed pH gradient was somewhat reduced, alleviating much of the problem. The lower than expected limestone utilization has not impacted byproduct gypsum marketability at Milliken and no further action is anticipated beyond extending the limestone addition piping 4-feet beyond the module wall to reach a more turbulent mixing area. Although the absorbers meet their design criteria for SO<sub>2</sub> efficiency and gypsum quality, even higher SO<sub>2</sub> removal efficiencies would be able to be achieved, at the same L/G's with a higher operating pH value. Changing the limestone addition point or the slurry bleed point would allow this pH increase without effecting the gypsum quality. In a commercial unit the bleed pumps should be located on the opposite side of the absorber from the limestone addition point.

The original design called for operation of the gypsum dewatering centrifuges with feed stream solids concentration of 25%. At this concentration the plant experienced difficulty in attaining specified centrifuge cake dryness. Centrifuge vibration was higher than desired. The concentration of the underflow from the primary dewatering hydrocyclones varied with the concentration of the absorber bleed slurry which ranged from 8 to 12 % solids. The limited surge capacity of the centrifuge feed tanks was inadequate to buffer these variations in concentration which caused non-uniform feed slurry density and uneven cake distribution within the centrifuges. The limited capacity of the feed tanks also caused interruptions in the centrifuge feed cycle which reduced system capacity. The feed solids concentration was increased to 50%. This change increased the effective capacity of the centrifuge feed tanks, resulting in more uniform feed slurry density, more uniform cake distribution within the centrifuge, less centrifuge vibration, and lower centrifuge cake moisture. Future commercial units should operate with the higher density slurries.

The miscellaneous slurry pumps have experienced wear of rubber-lined impellers and suction liners. Depending on the severity of the service, the rubber linings were found to wear down to bare metal within 3 months. The centrifuge feed pumps were relined with urethane. The urethane liners lasted over 12 months, a four-fold increase in life. The plant plans to change to urethane liners for all of these pumps in order to prolong liner life. Urethane should be considered in place of natural rubber for future commercial installations.



Rubber lining has peeled off from portions of the absorber modules' internal turning vanes. This problem has been worse in Unit 2 than Unit 1. Pieces of this rubber have been found plugging absorber nozzles and hydrocyclone apexes. The described failure mechanism is consistent with industry experience when rubber lining seams are oriented counter to the flow direction of impinging slurry sprays. The spray impingement peels the rubber back, sometimes to the bare metal. Repairs efforts have been unsatisfactory. The plant continues to experiment with alternative repair methods. In future commercial installations more stringent shop rubber lining specifications and inspections should ensure that rubber lining seams are properly oriented.

The inlet annubars used to measure the flow rate of flue gas to the absorber modules were found to read low by as much as 30%. The flow rate signal is used in the feed forward control of limestone addition. The selected annubar location does not have the requisite straight run of duct work for accurate flow measurement. The falsely low flow rate signals resulted in under-dosing of limestone. In order to achieve the required SO<sub>2</sub> removal the units had to run with more recycle pumps on-line to increase the L/G ratio. The units had difficulty following load swings and under-performed as regards SO<sub>2</sub> removal efficiency. The pH trim control could not add enough limestone to compensate. The Unit 1 annubar was replaced with an ultrasonic meter which greatly improved the performance. Subsequently the Unit 2 annubar was replaced as well. Both flow monitors work well. In a future commercial unit an alternate indication of flue gas flow rate, such as coal feed rate or boiler load, such as used in Europe, could be used to avoid the problems associated with measurement of gas flow rates in large ducts.

## **BRINE CONCENTRATOR SYSTEM OPERABILITY AND RELIABILITY**

The brine concentrator system has experienced numerous operating problem throughout the demonstration. Upon shutdown the vapor compressor would rotate in reverse. The compressor labyrinth seals, shaft and front shaft bearings were damaged. In the original design no back flow prevention was provided on the vapor compressor to prevent reverse rotation upon shutdown. A check valve was installed to prevent reverse rotation of the compressor.

The vapor compressor experienced high vibrations in the high speed bearing area of the gear box during startups. Excessive compressor vibration was attributed to two causes. The rotor which was originally supplied with the compressor was out of balance, causing it to vibrate. The compressor rotor out of balance condition was attributed to manufacturing errors. The compressor was designed to start up on brine, not on water. When starting up on water the compressor does not see adequate back pressure. Consequently the compressor would run out on its curve into an unstable operating region, again resulting in high vibration. A replacement rotor assembly was provided to solve the rotor out of balance problem. A back pressure control valve was installed to solve problem of low back pressure when starting up with water. Together these two remedies solved the compressor vibration problem.

The boron level in the brine concentrator feed stream was found to be appreciably higher than expected. The coal has been identified as the major source of the boron. A sampling and analysis program to characterize process chemistry in support of brine concentrator operation was formalized. As of October 1996 the calcium levels in the feed stream were within specified tolerances but the boron level was still elevated. The brine concentrator feed was analyzed for all other constituents required by the specification and this information was made available to the system supplier. In August, 1997 the brine concentrator supplier provided revised operating conditions and sampling protocol for brine concentrator system. The brine concentrator vapor compressor was rebuilt and additional chemical injection points were added according to the supplier's recommendations. The system ran for a ten day evaluation period beginning on December 8, 1997. NYSEG and the brine concentrator system supplier reviewed current *operating and chemistry issues on 3/19/98 and resolution of these issues is still pending.* Final determination as to the continued operation of brine concentrator system depends on the resolution of these issues.

For several days after startup with gypsum seed, the product tank overflow was milky white. The solids are not settling in the product tank as designed which resulted in exceedance of the specification salt product solids. Analysis showed these solids to be gypsum (as expected) but with particle size smaller than 5  $\mu\text{m}$ , as compared to the 20  $\mu\text{m}$  seed recycle system design basis. The gypsum particles are too small to be separated by hydrocyclone and too small to adequately settle in the product tank, creating the milky overflow. An additional process step was been added to resolve the issue suspended solids in the product tank overflow. This stream is now filtered by a small filter press to remove the solids, leaving a clear filtrate for export.

Suction piping to vapor compressor as well as brine concentrator experienced extensive pitting which can result in premature failure. Corrosion was also observed in the expansion joints in the compressor suction and discharge ducts. Corrosion has also been observed on the compressor inlet guide vanes. The vapor compressor suction duct and the expansion joints in the suction and discharge ducts and the compressor inlet guide vanes are all made of 316L stainless steel. Pitting corrosion in the compressor suction duct occurred due to exposure to low pH brine droplets carried over from the brine concentrator sump (even though the demister efficiency was very good). The low sump brine pH occurred because of certain minor constituents not expected to be present or expected in smaller quantities. The vapor compressor suction duct and the expansion joints in the vapor compressor suction and discharge ducts have been replaced with Hastelloy C276 materials. It is likely that the compressor inlet guide vanes will also be replaced with Hastelloy C276 or titanium alloy.

During the normal operation of the brine concentrator, the evaporator tubes gradually plug reducing the flow through the evaporator tubes. Eventually, the reduced flow causes a compressor trip due to surge. Inspection revealed scale inside the evaporator tubes. Scaling of the evaporator tubes was found to be due to precipitation of gypsum scale due

to chemical imbalances in the system. Process changes were implemented to add sodium sulfate and sodium hydroxide to the system in order to force the precipitation of gypsum on seed crystals. No plugging problems were experienced during the 10-day trial run in December, 1997. However, the resultant brine product had impurities concentrations higher than allowed by the product specification.

As of this report the ability of the brine concentration system to reliably process the effluent from the FGD blowdown pretreatment system while producing an acceptable byproduct remains to be demonstrated. NYSEG and the system supplier continue to investigate ways to improve system operation.

## **COMMERCIALIZATION POTENTIAL**

A key factor in the commercialization of FGD technology is that the market is driven by the rate of growth in the electric power industry and by the demands of the regulatory environment. Public Law 101-549, the 1990 Clean Air Act Amendment (CAAA), requires existing coal-burning power plants to reduce sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) emissions. Considering the technology options which are commercially available today, it appears that a significant portion of these existing plants will have to rely on wet flue gas desulfurization (FGD) and NO<sub>x</sub> mitigation upgrades to reach the levels of SO<sub>2</sub> and NO<sub>x</sub> required by legislation. In addition, the SO<sub>2</sub> emissions credit trading feature of the Clean Air Act Amendments places greater emphasis on ultra-high cost effective SO<sub>2</sub> removal capability. The ultra-high SO<sub>2</sub> removal capability of the SHU process, i.e., up to 98 percent SO<sub>2</sub> removal (as demonstrated by the MCCTD Project), is thus a significant selling feature.

Competing lime and limestone-based flue gas desulfurization processes produce large quantities of solid waste byproducts. The waste produced by many of these technologies has no commercial value and must be landfilled. The SHU process can produce commercial grade, as opposed to disposable grade, gypsum by washing the gypsum for chloride and formic acid removal during dewatering. The SHU process produces a 100 percent yield of high quality gypsum crystals suitable for the wallboard or cement industries. As suitable landfill sites become harder to find and as the costs of landfilling large quantities of power plant waste rise, processes such as SHU which can economically produce a marketable byproduct should have a significant competitive advantage.

Competing lime and limestone-based flue gas desulfurization processes impose significant auxiliary power requirements on the host power plant, resulting in lower station heat rates and increased greenhouse gas emissions per unit of net power generation. The SHU process offers reduced auxiliary power consumption compared to some competing processes due to more efficient oxidation, lower L:G ratio, increased limestone utilization, absence of gypsum fines, and lower gas-side pressure losses. As deregulation forces more rigorous economic competition among power generators and as concerns regarding the global buildup of greenhouse gases begins to affect the

marketplace, these competitive advantages of the SHU process should be reflected in increased marketability.

While Saarberg-Hölter Umwelttechnik GmbH, a German company, owns the SHU process license and will supply the basic process engineering, a majority of detailed design services and all equipment will be supplied by U.S. companies. This will aid in the development of the U.S. manufacturing base that will be supplying the process to the US power industry.

The SHU process is a highly cost competitive FGD process. Preliminary evaluations by an industry research institute indicated that SHU technology may be the most cost competitive of the FGD processes for achieving high SO<sub>2</sub> removal rates with a limestone-based system. With the MCCTD project's confirmation of this expected cost savings, the SHU process should capture a large share of the US FGD market due to requirements for retrofit or new plant SO<sub>2</sub> emission controls.

The SHU technology has wide-spread application within the utility and industrial market. With slight modification, this process has been used in Europe to successfully reduce SO<sub>2</sub> emissions generated from boilers fired with lignite, oil, and gas; industrial boilers; and also in municipal waste incinerators. This process also has the potential for use in reducing SO<sub>2</sub> emissions associated with coal gasification, shale oil retorting, and Orimulsion. The process is applicable to boilers firing low, medium or high sulfur coals, without limits as to boiler size or type, providing SO<sub>2</sub> removals of up to 98%. As with any wet limestone FGD process the SHU technology requires a significant amount of plot space on site, though the amount of space required can be minimized by adoption of the split module, below-stack configuration demonstrated by the MCCTD project.

A fully detailed analysis of the potential FGD market is provided in Volume I of the *Public Design Report*. The analysis forecast a large market share of both retrofit and new capacity plants for the SHU FGD process. Initially, this market would be stimulated by electric utility power plants requiring FGD retrofit to comply with Clean Air Act Amendment legislation, with plants responding to this legislation with applications starting in 1995. It was assumed that the retrofits would continue for a finite period, 15 years. As a result of the MCCTD project, the SHU technology would be fully commercialized by 1999. The analysis assumed that the SHU process would be able to penetrate the new United States power plant market by 1996. Based on this analysis, projected SHU FGD market share for retrofits in the U.S. through the year 2030 totals 5,700 MW. The projected SHU FGD market share in the U.S. for new power plants through 2030 totals 96,200 MW. The balance of the retrofit and selected new power plant markets will use other available sulfur reduction technologies.

US utilities are reluctant to invest in a technology which remains unproven within the US, where fuels and operating conditions generally differ. Further, some US companies are reluctant to purchase equipment from international suppliers. However, the successful demonstration at Milliken Station, in conjunction with SHU's experience in Europe,

should enable SHU to effectively market the FGD technology in the US, through its US design and manufacturing partners.

## **8.8 ABSORBER MIST ELIMINATOR PERFORMANCE**

A droplet carry over testing program was conducted to evaluate the performance of the Milliken absorber mist eliminators. Each of the two Milliken units has a single-module absorber for flue gas desulfurization. Each absorber module is equipped with two stage mist eliminators. The flue gas exhausted by each unit is discharged through separate flues in a common stack. Droplet tests were conducted at the inlet to the first stage mist eliminator Unit 1, at the outlets of the mist eliminators for each of the two units, and in the flues for each of the units near the top of the stack. Tests were conducted at three load conditions at each of these five test locations: low load (nominally 120 MW), high load (nominally 150 MW), and in what is called "crossover-mode" operation (each unit operating nominally at 105 MW with the combined flow from both units passing through the single absorber being tested). The tests were conducted over the period October 1 through October 9, 1996. The tests included traverses of representative sections of the test locations using standard pitot methods to measure gas velocities over the measurement planes, and measurements of droplet concentrations with the Southern Research Video Droplet Analyzer (VDA). The rate at which water was collected by a stack drain system mounted within the flue of each unit was also measured during most of the tests.

The performances of both mist eliminators were comparable at the low-load and high-load test conditions. The Unit 1 ME performance was clearly superior at the crossover test condition. Further, the carryover from both mist eliminators was dominated by emissions resulting from washing. The rate at which liquid was collected by the stack drain systems was higher for Unit 1 than for Unit 2 for comparable test conditions in all cases and the stack drain system collection rates were greater for either unit at low-load as compared to high-load or crossover mode operation. For either flue, the stack drain collection rates for high-load and crossover mode operation were comparable.

## 8.9 STEBBINS TILE TEST FACILITY

As part of a separate study being performed to determine the maintainability of a tile lined FGD absorber module, NYSEG installed a test module at Kintigh Station. The facility was designed to:

- assess/evaluate mortar and tile wear and erosion,
- determine the effect of damaged tiles on the underlying concrete integrity,
- verify that tile glaze thickness does not affect the water penetration rate,
- verify and demonstrate on-line concrete crack repair, and
- verify that wall penetrations can be made leak tight.

The facility was 7 ft by 7 ft plan area (outside dimensions) by 8 ft tall, with walls 10 in thick. Slurry from one of Kintigh Station's six SO<sub>2</sub> absorber modules was circulated through the test module. The walls of the test module were constantly sprayed using supernatant from Kintigh Station's absorber thickener. The test module was continuously stirred with a double-blade slurry mixer. Three cracked tiles (one below, one at, and one above the water line) were purposely installed on each of three of the walls; the fourth wall was a control wall with no damaged tiles. Thirty concrete test cylinders (6 in diameter) were placed inside the tank for periodic compressive strength and chloride penetration evaluation. The test module received a slip stream of absorber slurry to simulate operating conditions and was in service for three years. By intentionally damaging the interior of the test module, three repair procedures were tested and proven reliable. The three conditions tested included cracks in grout, cracks in tiles, and holes penetrating the module wall. A chemically resistant epoxy based grout was used to repoint areas that had cracked or where existing grout had eroded. Complete tiles can be replaced by chipping out the old tile, removing two inches of concrete behind the tile, resurfacing with a Portland cement, cementing the new tile in place, and regrouting with a chemically resistant grout mixture. To repair holes on-line, holes were drilled around the leaking area in a random fashion, the new holes were fitted with special Zerk type grease fittings, finally a grease gun was used to pump water and then a chemical grout foam into the new holes.

After two years of operation, the tiles appeared to be in good condition with no obvious erosion or deterioration. Tile areas where the wash spray impacted directly appeared to be slightly lighter in color than the surrounding areas; the darkness of the surrounding areas might have been due to deposition of a thin surface scale. The tile grouting was hard and appeared to be undamaged in any way except for two locations, 5-6 in long by 1/2 in deep, where the grout eroded, apparently due to spray impingement.

The three cracked tiles, originally purposely installed, on one of the walls were replaced

after one year of operation. No leaks were observed from the replaced tiles.

A method for sealing a leaking area was tested by drilling eight holes, 5/16 in diameter by 91,4 in deep through the tile, into the concrete to establish liquid weep from the tank to the outside. Five months later, the area was sealed by a Stebbins field representative using a chemical method developed by Stebbins. Two years later, the area appeared to be dry with no evidence of additional leaks.

During the week of December 8, 1997, the test module was inspected and demolished. Inspection of the test module included:

- Photographs of the tile-lined interior of the module.
- Grout joint profile depth measurements around the "Refrax" plugs on the north and south walls.
- Removal of six test cores from the north, south and west walls.
- Inspection of steel reinforcement bars as the concrete walls and base were demolished with a jackhammer.
- Concrete cylinders submerged in the limestone slurry at the bottom of the test module were removed for compressive strength and other testing.

The total elapsed time on the test module was 3.2 years since start-up. The slurry pump which circulated limestone slurry through spray nozzles pointed at the four walls operated a total of 1.8 years.

The major results of the examination included the following:

- The tile on the interior of the module appeared to be in good condition with no obvious erosion or deterioration of either the glazed or unglazed tiles.
- The tile grout (Stebbins AR-196 Resin Cement) showed no signs of deterioration.
- Grout joint profile depth measurements around the "Refrax" plug did not reveal any signs of grout erosion.
- A visual examination of the six cores removed from the walls revealed the presence of shrinkage or thermal cracks and parting lines between concrete pours. None of these cracks and parting lines affected the performance of the tile lining. Detailed testing of the cores may be done at a later date.
- The steel reinforcement bars in the walls showed no signs of corrosion even in areas where leakage was allowed to occur.



- The steel reinforcement bars set in the concrete foundation slab to serve as dowels from the slab into the walls were corroded at the parting line between the concrete slab and the concrete wall which were poured at different times. No external leakage was ever observed at the foundation slab along the east and south walls where corroded dowels were found. Some corrosion was also found at a location lower on the dowel which would be further into the slab. During the demolition, it was also noted that the mastic sealant, normally applied between pours, was adhering to the dowels which was not observed at all the other areas where the mastic sealant had been applied. According to original drawings, the dowels were to pass through a keyway in the slab. Instead, the dowels were set just behind the first row of tile. This may have prevented the mastic sealant from being set down to the concrete surface of the slab at the dowels. The presence of corrosion on the dowels in these areas seems to indicate that some leakage occurred in the grout joint between the floor tile and wall tile. The mastic sealant failed to keep the liquid from contacting the dowel bar. The amount of leakage was apparently very small since there was never any sign of leakage at the exterior of the slab.

Overall, the test facility confirmed that leak repair is simple and effective. The effects of leakage on concrete appears minimal. Tile and mortar wear are undetectable and maintenance has not been required.

## **COMMERCIALIZATION POTENTIAL**

Although Stebbins, one of the largest tile companies in the U.S., has effectively commercialized the use of its tile for the industrial market (chemical and pulp/paper industry), the use of Stebbins tile and mortar system as a lining for an FGD absorber had not previously been demonstrated sufficiently to prove its viability and acceptability to the satisfaction of the electric utility industry. Prior to the MCCTD project Stebbins tile had been applied as a liner to a horizontal Kellogg Weir absorber. The MCCTD application is substantially different from that used in the Kellogg unit. The SHU system provided a harsher environment in which to demonstrate the durability of Stebbins tile. The SHU absorber has vertical cocurrent and countercurrent gas flow whereas the Weir scrubber is a horizontal gas flow absorber. In addition to having an increased velocity, the SHU recycle slurry is more acidic, has a higher chloride concentration, and includes an organic acid buffered chemistry. The successful demonstration at Milliken Station has helped Stebbins to effectively market this product as an absorber liner to U.S. utilities and FGD vendors.

Because the MCCTD split module absorber design consists of a below-stack absorber, demonstration of its effectiveness should enhance the acceptance of Stebbins technology as a retrofit option to a large number of existing plants with problems similar to that of the Milliken Station: limited site space. Absorber construction systems, such as Stebbins', offer below-stack designs which will fit at existing sites where other types of construction would otherwise have to find expansion room that is often unavailable.

Construction costs at constricted sites are higher, and therefore there are design compromises, and construction is difficult. Site-specific retrofit FGD cost is lower for below-stack designs than for those designs which do not allow below-stack absorbers. The constricted site advantages of Stebbins' construction are not limited to below-stack designs. Limited construction access is not a barrier to implementing the reinforced concrete/tile lined system. This enables a utility company to retrofit a Stebbins constructed absorber between existing structures without having to provide a large amount of space for cranes to lift large sections of steel or alloy absorber shell.

The SHU process operates at lower pH and at higher chloride concentrations than other wet lime/limestone processes. This presents a potentially more corrosive environment in the absorber. Additionally, the SHU process with its cocurrent/countercurrent design requires an interior wall with both sides exposed to the process. Successful demonstration of the Stebbins tile system in this application will further reinforce its acceptance as a construction option, when compared to high nickel alloys.

Conventional lined carbon steel and alloy absorber construction require that the absorber module be shutdown in order to repair leaks in the absorber walls. A valuable asset of Stebbins' construction is that leaks in exterior walls can be repaired from outside the absorber vessel, even with the absorber in operation. This advantage maximizes absorber availability and reduces the need for a spare absorber module, saving plot space and capitol cost. These are important considerations for a utility company selecting an absorber approach.

A significant detriment to the availability of conventional absorber designs is their susceptibility to damage when exposed to upset conditions of high temperature flue gas. Such exposure can occur due to an air preheater failure or due to a power outage that interrupts the absorber quench and recycle sprays. Stebbins' construction is able to withstand these upset conditions, obviating the need for extensive relining outages, thereby enhancing absorber availability. This enhanced availability further reduces the need for a spare absorber module, presenting utility companies with significant plot space and cost savings.

The Stebbins system can be implemented as a separate structure for new or retrofit installations, or implemented, as at Milliken Station, as a below-stack absorber to save space. It can also be implemented as a single module or implemented as a split module absorber. In addition, the construction can be implemented for virtually any of the currently available wet lime or limestone FGD process designs as well as for the SHU process.

The demonstration of Stebbins ceramic tile offers several advantages to the utility marketplace. These advantages include on-line repair, a reduction in maintenance cost and increased reliability. The split module absorber cannot be constructed with rubber lined, flakeglass lined, or alloy clad vessels. The ability to provide individual modules at a relatively low cost is a very marketable concept. The most marketable aspect of the tile

itself will most likely be its expected lower lifecycle costs compared to other materials of construction. Lifecycle costs associated with the tile and mortar lining system used at Milliken are expected to be substantially lower than those of competing absorber construction materials such as rubber lined steel, flakeglass lined steel, alloy lined steel or solid stainless steel. In addition to increased reliability and decreased maintenance, the expected life of the tile lining is three to four times that expected for rubber liners.

Because the demonstration project was scheduled for only three years of operation, the total potential lifespan for the Stebbins tile could not be assessed. However, the viability of the split module concept has been fully demonstrated. The combination of the durability and reliability already demonstrated within the non-FGD industrial market and the Milliken Station demonstration should enable Stebbins to effectively market this product to FGD vendors and utilities.

A fully detailed analysis of the potential market for Stebbins tile absorbers is provided in Volume I of the *Public Design Report*. Based on this analysis, the Stebbins tile absorber technology has the potential of increasing its share of the FGD absorber market to approximately 24 percent by the year 2030. The projected Stebbins absorber market share for retrofits in the U.S. through the year 2030 totals 4235 MW. The projected Stebbins absorber market share in the U.S. for new power plants through 2030 totals 72,000 MW.

The approach to commercialization of the Stebbins Tile Absorber Construction requires a different path to commercialization than normally associated with a new product. As a result, the difficulties and schedule to commercialize are greatly reduced. Several critical factors normally affecting commercialization of a particular product or process are not applicable to the Stebbins Tile Reinforced Concrete Absorber. For example, financing to develop the technology and manufacturing of the technology need not be addressed, since the process engineering and major components and construction methods have been previously developed. Early commercial introduction in the U.S. FGD absorber market is also possible because The Stebbins Tile Reinforced concrete construction system has already been successfully commercialized. The Stebbins process has fully proven itself in similar applications in the pulp and paper, chemical and mining industries. This construction system is familiar to the utility industry through its use in auxiliary scrubber related power plant tankage. The tile and grout portion of the Stebbins system has proven its corrosion/abrasion resistance as a replacement for failed liners in several FGD absorber and flue gas duct applications. Additionally, this technology had been used in conjunction with the M.W. Kellogg Horizontal Weir Absorber process design since 1982 at the Big Rivers Electric D.B. Wilson station.

Based on this, the steps required for the commercialization of the Stebbins Tile Reinforced Concrete Absorber construction in the U.S. are:

- Demonstration at a scale large enough to establish user confidence in the available savings in plot space, construction access and construction costs.

- Prototype testing at a large (300 MW) operating utility power plant.
- Further establishing U.S. utility confidence in the technical and economic worth of the approach.

All of the above are demonstrated by the Milliken project. Following that demonstration, the final step becomes possible.

- Widespread commercial application.

Commercialization of the Stebbins Tile Reinforced Concrete Absorber Construction was initiated during the demonstration and has been ongoing throughout the project. It should be fully commercialized by 1999.

## 8.10 HEAT PIPE AIR HEATER EVALUATION

### PROGRAM GOALS AND RESULTS

A main goal of the Department of Energy's (DOE) Clean Coal Technologies IV test program at the New York State Gas & Electric Company's (NYSEG) Milliken Station was to demonstrate overall pollution abatement with increased energy efficiency. To reduce plant air emissions, SO<sub>2</sub> and NO<sub>x</sub> control systems were retrofitted on both the Unit 1 and Unit 2 boilers. Innovative technologies, such as the use of heat pipe air heaters on the Unit 2 boiler were incorporated into the design to lessen the impact of the new emission control systems on the overall plant heat rate. The heat pipe air heaters were designed and manufactured by ABB Air Preheater Inc. of Wellsville, New York. Expected benefits of replacing the two original Ljungstrom® regenerative air heaters on the Unit 2 boiler with the heat pipes included: (1) higher heat recovery by allowing operation at a lower effective flue gas outlet temperature than the original air heaters, and (2) reduction in the overall boiler-FGD system fan power requirements by elimination of the air leakage inherent in the design and operation of Ljungstrom® air heaters.

Detailed tests and analyses indicate that the thermal performance of the heat pipes is about the same as the original air heaters. The goal of a 20 °F reduction in the effective air heater flue gas outlet temperature was not achieved. However, the use of the heat pipe exchangers successfully reduced air heater leakage to near zero levels. This is improving the boiler heat rate by greatly reducing the fan power requirements for the system. At full boiler load, the fan power savings comparing Unit 2 with Unit 1 averaged 778 KW or about 0.49% of the gross load.

Cold-end fouling of the heat pipes is the main operating concern. The fouling reduces the thermal performance and increases the gas side pressure drops with time. Normally, the heat pipes must be washed every six months to remove cold-end deposits. Based on the most recent plant operations, there are now indications that the operating period between washings can be extended by limiting the minimum boiler low load to 80 MW. This practice helps to avoid excessively low cold-end temperatures which increase fouling.

### INITIAL PERFORMANCE PROBLEMS AND SOLUTIONS

The heat pipe air heaters were put into service in December 1994. The initial operations indicated that performance was significantly below design. The cause was traced to problems with the inlet air flow distribution to the heat pipes and to the use of impure naphthalene heat transfer fluid in some of the high temperature tubes. The naphthalene problem was due to suppliers not meeting the ABB/API purity specifications. Analysis of heat pipe tube contents indicated that naphthalene contaminants had decomposed forming mixtures of non-condensing gases composed of hydrogen, carbon dioxide, and ethylene. The non-condensing gases reduced the heat pipe thermal efficiency by

blanketing heat transfer surface and by raising operating pressures and temperatures of individual heat pipes.

To solve the air flow distribution problem, perforated plates were installed at the discharges of the primary air and secondary air fans. Condenser end baffle plates were also installed within the heat pipes to force combustion air flows away from potentially non-active heat transfer zones into active zones.

The decomposition of naphthalene contaminants is believed to be a one time occurrence. Therefore, to remove the non-condensing gases, ABB/API installed fill nipple valves on all the naphthalene tubes. The heat pipe tubes were then re-evacuated under cold conditions and vented under hot conditions. After these changes were made, performance tests were conducted during May 1996 and November 1996. The tests demonstrated that the heat pipes were meeting the design pressure drops and that the total air leakage into the flue gas side of the air heaters was low, averaging 3.0 wt % and 1.6 wt % of the inlet flue gas flow for the 2A and 2B heat pipes, respectively. The heat pipes were, however, designed to have zero percent air to flue gas leakage. Since the construction is all welded, it is unlikely that the combustion air is leaking into the lower pressure flue gas section. Rather, air infiltration at man way door seals and at sootblower wall penetrations is mainly responsible for the very small measured leak rate. For practical purposes, the heat pipes are zero leak air heaters and are considered to have met this design guarantee.

## **HEAT PIPE AIR HEATER THERMAL PERFORMANCE**

The ASME Code procedure for testing air heaters was followed to provide a consistent evaluation method agreed upon by both the purchaser and supplier. The thermal performance of the heat pipes, while reasonably good, did not meet the design guarantees. For the May 1996 tests, the totally corrected flue gas outlet temperature for the 2A heat pipe was 17 °F-18 °F above the 253 °F design temperature and for the 2B heat pipe was 12 °F above the design. For the November 1996 performance tests, the differences were slightly higher at 20 °F-23 °F for the 2A heat pipe and 15 °F - 16 °F for the 2B heat pipe. Based on an analysis done by CONSOL R&D, the uncertainty in these results is  $\pm 4.4$  °F. These results mean that the desired thermal performance improvement of 0.5% was not achieved. This is based on a typical boiler efficiency improvement of 1% for every 35 °F reduction in the flue gas outlet temperature (no leak condition) from an air heater. However, an energy loss to stack comparison indicates that the clean condition heat pipe thermal performance is equal to and no worse than the performance of the original Ljungstrom® air heaters.

## **MEASURED BENEFITS OF REDUCED LEAKAGE**

Although the thermal performance of the new heat pipe air heaters was not better than the replaced Ljungstorm® units, the use of the heat pipes provided considerable improvement in fan power requirements. This is shown by direct comparison of the Unit 1

and 2 operating results for similar conditions of boiler excess air and gross load. Such a comparison is justified since Milliken Units 1 and 2 are identical except for the use of Ljungstrom® air heaters with hot primary air fans in Unit 1 and heat pipe air heaters with cold primary air fans in Unit 2. At 100 MW and 160 MW gross load, the Unit 2 combined power requirements for the primary air, secondary air, and induced draft (ID) fans, averaged 0.67MW (900hp) and 0.78MW (1050 hp) less than for Unit 1, respectively. Most of the power savings can be attributed to the lower combustion air and flue gas flows for the Unit 2 boiler due to the zero air leak operation of the heat pipe air heaters. The differences represent considerable power cost savings for the zero leak heat pipe system. Assuming incremental costs of 2.3¢/kW and a 65% plant capacity factor, the 25 year life cycle power cost saving is estimated at \$2.5 5MM. Actual power cost savings are likely to be greater since these results have not considered power reductions for the electrostatic precipitator and the FGD system with optimized pumping (i.e., headers removed from service to accommodate reduced flue gas flow).

## **COLD-END FOULING**

The main operating problem experienced with the heat pipe air heaters was flue gas side fouling of the cold-end tube banks. As with other types of utility boiler air heaters (Ljungstorm® and tubular units), the heat pipe fouling was associated with sulfuric acid condensation on heat transfer surfaces which are below the acid dew point. Fouling created hard fly ash deposits on the heat pipe tubes and fins which reduced the heat pipe thermal performance and increased the flue gas side pressure drop. The fouling was promoted by direct gas flow impact since the worst fouled areas were against the gas flow on the top side of the tubes. The fouling was localized and limited to the cold-end tube banks.

The Milliken heat pipes were designed with a triangular-pitch, staggered-tube bundle layout throughout. The design provides high heat transfer and is compact. However, the design makes the cold-end difficult to clean by conventional sootblowing when sticky cementitious ash deposits form. For close packed tubes, the staggered layout quickly dissipates most of the sootblower jet energy within the first two tube rows. During the heat pipe test program, attempts were made to improve the on-line cleaning of the cold-end tube banks. An Infracone® was installed on the 2A heat pipe and four sootblower lances in the 2B heat pipe were modified by replacing the standard Bergamann 'A' cone nozzles with special s/a" venturi nozzles. The Infracone® is a device which uses high intensity, ultra low frequency sound for on-line equipment cleaning. Neither the Infracone® nor the modified sootblower lances appeared to provide any significant cold-end cleaning benefit over the existing sootblowers. The Infracone® operation was discontinued after over 300 days of service due to vibration-caused damage to ductwork and equipment.

Cold-end deposits, while a nuisance and detrimental to plant performance, can be removed by periodic water washing. Unlike the Unit 1 Ljungstrom® air heaters, that can be washed with the boiler on-line at low load, the Unit 2 heat pipes require that the boiler

be shut down prior to cleaning. This is because the heat pipes require some manual cleaning. At Milliken, the heat pipe air heaters are water washed approximately every six months. The best technique is to use a combination of deluge washing using the internal water spray headers with the air sootblowers in operation and manual washing with small low pressure hand lances to clean areas missed by the deluge washing.

The heat pipe performance results for the most recent six month operating period (October 31, 1997 to April 24, 1998) indicate that it may be possible to extend the period between washes by limiting the minimum boiler load to about 80 MW, maintaining flue gas flow balance between the air heaters, and by bypassing some secondary air at off peak load conditions. These adjustments help to prevent operation of the cold-end heat pipes at excessively low temperatures. During the last six month operating period, the full load flue gas side pressure drops increased only about 1 in. WC compared to the normal 3-5 in. WC increase.

## **CONCLUSIONS AND RECOMMENDATIONS**

The ABB/API heat pipe air heaters at Milliken are providing significant boiler operational benefits through elimination of air leakage associated with the originally installed air heaters . The Unit 2 combined horsepower for the primary air, secondary air, and ID fans is typically over 1,000 hp less than for Unit 1 under full boiler load conditions. However, in order for the heat pipe air heaters to meet their full potential, progress must be made to improve the on-line cleaning of the cold-end sections. Possible improvements include:

1. Relocating some of the upper level sootblowers to increase the number of sootblowers around the cold-end modules. This would increase the sootblower coverage. Inspections of the heat pipes have shown that the upper level sootblowers are probably not necessary since tube metal temperatures are above the acid dew point and the fly ash does not stick to the tubes.
2. Splitting the eight tube row deep cold-end module into two four tube row deep modules with a level of sootblowers between. This would improve cleaning by reducing the required penetration for the sootblowers.
3. Replacing the staggered tube layout cold-end module with an in-line tube layout. This would help to provide deeper penetration of the sootblower jets but would require more tubes than the staggered arrangement.
4. Replacing the finned tube cold-end module with a smooth tube module. A no-fin design would require more tubes since the heat transfer per tube would be reduced but cleaning should be easier since there would be less support for deposit adherence.



5. Changing the orientation of the sootblowers from perpendicular to the tubes to parallel with the tubes. This would help increase sootblower penetration by providing better alignment of the sootblower jet with the flow channels through the tube bank.
6. Reducing the flue gas  $\text{SO}_3$  level to the heat pipe air heaters by injecting additives such as  $\text{Mg}(\text{OH})_2$  or  $\text{MgO}$  into the boiler. Reducing the flue gas  $\text{SO}_3$  level would decrease the acid dew point and allow lower temperature operation without condensation. This form of  $\text{SO}_3$  control is now used mainly in oil-fired boilers and several companies can supply the reagents. However, tests are recommended for this option to determine the cost/benefits and to establish the impact if any on the ESP particulate collector.

Recommendations 1 and 6 are the easiest to achieve at the Milliken Station. Because of access limitations around the heat pipe air heaters, the other recommendations are likely to be difficult to implement and costly. Recommendations 2 through 5 are better suited for consideration in a new system design.

There is a concern that the heat pipe thermal performance may be slowly degrading due to loss of naphthalene. This is due to the installation of purge valves on the fill stems of all naphthalene heat pipe tubes. The valves were installed to vent non-condensing gases which were generated by small amounts of naphthalene contaminants. After purging the gases, the valves were closed, capped and left in place. This provides the ability to again vent the tubes if additional decomposition were to occur but presents a continuing potential for naphthalene leakage past valve stem seals. Normally, the fill tubes are crimped shut and the ends seal welded to prevent any possible fluid loss. Plant personnel have periodically used a photo ionization detector to check for heat pipe condenser end naphthalene leaks when the heat pipes were in operation. The checks have shown varying levels of naphthalene at the test ports. The last check done in December 1997 showed a steep decline in naphthalene levels at all test ports. This likely means that the leaking tubes are now empty. For the Milliken heat pipe installation, periodic naphthalene leak checks will continue to be necessary to determine if additional tubes begin to leak. If this occurs, it may be necessary to remove the fill stem valves, refill the empty tubes and then to crimp and seal weld the fill stems.

Finally, the Milliken Station heat pipe air heater experience has pointed out the need for better quality control of the heat transfer fluids used in the fabrication. Fluid purity is critical if good performance and long-term operability are to be achieved. It is recommended that both the vendor and purchaser confirm the purity of each chemical batch. This would provide a double check and help to insure against non-condensable gas generation from contaminants.

## 8.11 MATERIALS OF CONSTRUCTION

The Milliken Materials of Construction program reviewed material selection and installation procedures for the CCTD project components, including corrosion monitoring of FGD inlet (heat pipe air heater outlet) ductwork, documentation of Stebbins tile design, construction methods and performance. Included are the results of long term testing of materials of construction, maintenance requirements, and reports of contractor inspection of metals, coatings, tile and stack materials during outages. Key findings are as follows:

- During the first two years of low-NO<sub>x</sub> burner operation, the boiler water wall tube wastage rate between the burners and the soot blowers increased to 16 mils per year (mpy) from a baseline rate of less than 5 mpy. However, the wastage rate during the third year of operation returned to the baseline rate, probably the result of improved boiler operation. As a precaution, the boiler water wall tube thickness should be measured again to confirm the return to the baseline wastage rate.
- The Mentor I corrosion monitoring system indicated that there was no measurable corrosion of Cor-Ten® A material and only 3 to 5 mpy wastage for the SA-178A carbon steel material between the air heater and the absorber.
- The Stebbins ceramic tile lined absorbers and the tile grout were in excellent condition with no obvious erosion or deterioration. Gypsum scale deposits were easily removed with the spray from a fire hose. The only cracks observed were in the first row of tiles at the top of the absorber the cracks seemed to be caused by load stress from the structure above the tiles.
- The acid brick transition between the carbon steel duct and the tile-lined absorber experienced isolated wear and erosion on some individual bricks; there was no consistent wear pattern in any general area. The worn bricks probably came from a bad lot. The wear did not warrant replacement of the bricks.
- The rubber linings on most of the absorber recirculation pumps degraded after eight months of operation. The liners were replaced with polyurethane; as of the 1997 outage, the replacement liners were in good condition.
- Heavy pitting occurred on the back of the absorber agitator impellers in both units. Corrosion or erosion is assumed to be the likely cause of the observed pitting. Hairline cracks were observed on four of the impeller blades; the agitator manufacturer replaced the cracked blades at no charge.
- There were no obvious signs of mist eliminator degradation or missing pieces. Scale deposits were less than one-eighth inch thick, except in the corners where the water wash sprays did not reach.
- The hydrocyclones were in good working order with no substantial wear or scale buildup on the internal walls.

- Corrosion occurred at the lifting lug attachments on the flakeglass coated carbon steel transition section between the absorber exit and the stack. The lifting lug attachments did not provide the proper surface profile for coating application. The corroded areas were touched up with high temperature epoxy and no subsequent corrosion has been observed. The process tanks lined with flakeglass coating and the rubber-lined process tanks were in good condition with no observable corrosion.
- The fiberglass reinforced plastic stacks showed no signs of erosion or corrosion. Several occurrences of erosion or cracking of the fiberglass piping occurred, mostly due to improper design, installation and support, or to direct impingement of slurry from a broken nozzle.
- The vulcanized rubber coating on the turning vanes, flow splitters, supports and entry doors showed a tendency to blister and sometimes peel off, exposing the metal underneath. Some of the pieces were later found clogging the recycle slurry spray nozzles. The blistering/peeling problem has not been solved.
- The silicon carbide recycle spray nozzles were prone to breaking. Nozzles made from Stellite® did not break. Pigtail-type nozzles tended to plug with hard deposits or pieces of rubber laminate. This was solved by using a strainer on the recycle pump inlet or by using an alternative nozzle design.

## 8.12 ENVIRONMENTAL MONITORING

### AIR QUALITY

As part of NYSEG's Milliken Station Clean Coal Technology Demonstration project, a flue gas desulfurization system was added as well as modifications to the combustion system and electrostatic precipitator. These modifications have resulted in a net reduction in air pollutant emissions from Milliken.

The burners were replaced with Low NO<sub>x</sub> Concentric Firing System Level 3 (LNCFS-3) burners to reduce NO<sub>x</sub> emissions while maintaining high combustion efficiency and acceptable fly ash loss on ignition (LOI). The achievable annual NO<sub>x</sub> emissions, estimated using long-term measurements, were .61 lbs/mmBtu for baseline operations and .39 lbs/mmBtu for post retrofit operations. This equates to a 36% reduction in NO<sub>x</sub> emissions.

The electrostatic precipitators (ESP) on the two 160 MWe boilers were upgraded to accommodate the wet flue gas desulfurization system. Upgrades of the ESP on each unit consisted of replacement of the internals and retirement of part of the original ESP. Performance tests conducted on the original and modified ESPs documented the improved performance of the retrofit. The modified ESP with less than one-half of the collection plate area has better removal efficiency than the original unit. The voltage-current product data indicate that the power requirement is 25% less than that of the original ESP.

The flue gas desulfurization system became fully operational in June 1995. The average removal efficiency for the system is approximately 88%. This includes testing periods in which operating conditions were varied to determine effects on removal efficiencies. The FGD system has essentially operated during all periods of boiler operation except startup and shutdown.

The ambient levels of SO<sub>2</sub>, NO<sub>2</sub>, O<sub>3</sub>, TSP and PM<sub>10</sub> at all sites were found to be below ambient air quality standards throughout the entire 4-year ambient monitoring program. Analyzing the ambient air quality data collected in the surrounding area for the two years prior to NYSEG's Milliken Station FGD retrofit and the year and a half after the retrofit, significant changes to the ambient air quality were identified. The ambient SO<sub>2</sub> levels showed a reduction by an average of 40-50% over the course of the 4-year air monitoring study. The ambient NO<sub>2</sub> levels also were reduced by an average of 10-15% at the North and South sites, while very little change was observed in the NO<sub>2</sub> levels at the East site over the same period of air monitoring. Ambient ozone levels appeared to be reduced slightly over the period of monitoring, while no discernible changes were observed in the TSP and PM<sub>10</sub> ambient levels.

## SOLID WASTE

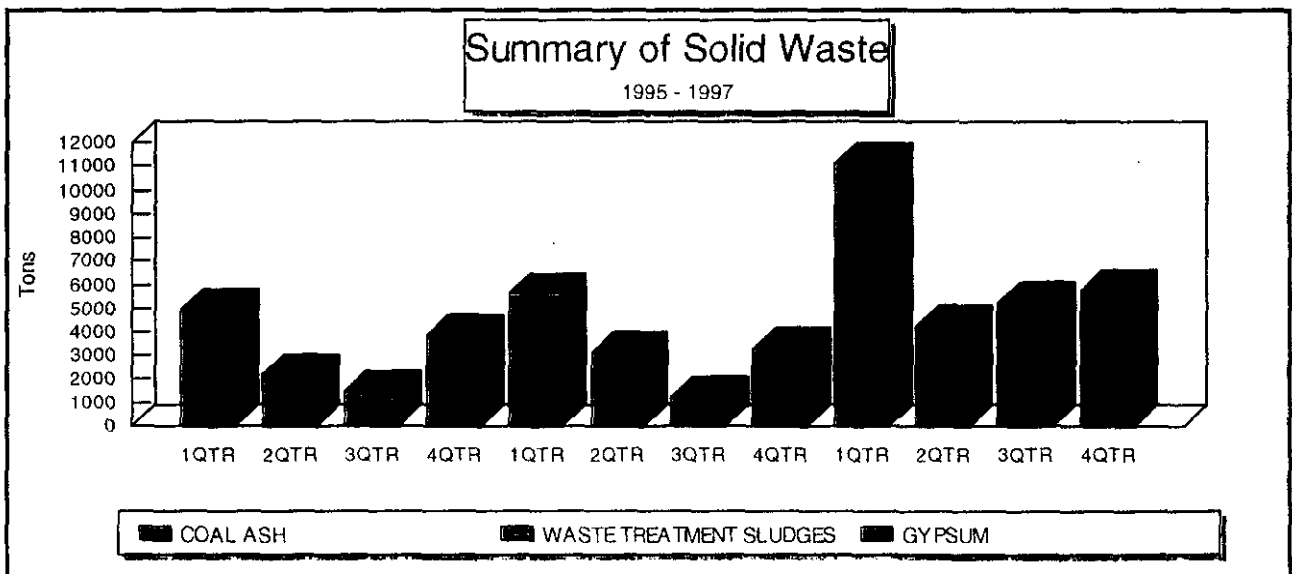
Milliken Station operates a solid waste disposal area east of the plant which encompasses approximately 41 acres. The disposal area began operation in 1978 and accepted primarily combustion byproducts from Milliken Station which included fly ash, bottom ash and pyrite rejects. In addition the facility received sludges and sediments from maintenance cleaning wastes from Milliken Station.

Extensions to the landfill were made in 1978, 1979, 1982, 1984, 1986 and 1990. Currently only the 1986 and 1990 extensions are active. The active portion of the landfill utilizes a modified composite liner consisting of a low permeability soil liner, a leak detection system, a synthetic liner, and a leachate collection system. The closed portions of the waste disposal area utilized a low permeability soil liner design meeting the effective regulatory requirements with leachate collection and a low permeability cap covered by top soil as a final cover.

The 1984, 1986 and 1990 extensions are hydraulically and operationally separate from the previous extensions to the waste disposal area.

Solid waste generation during 1995 - 1996 is depicted on Figure 8.12-1. Fly ash disposal is initially high due to the tuning of the LNCFS-3 burners. Fly ash disposal dropped off during the course of the year as optimization of the burners was finalized. During the second quarter of 1995 gypsum disposal was due to the problems experienced with the centrifuges. However, during the fourth quarter the jump in gypsum disposal was primarily market driven as NYSEG negotiated a final purchase agreement with a wall board manufacturer. Sludge disposal increased as a result of starting up the FGD brine feed water treatment and both FGD modules becoming operational.

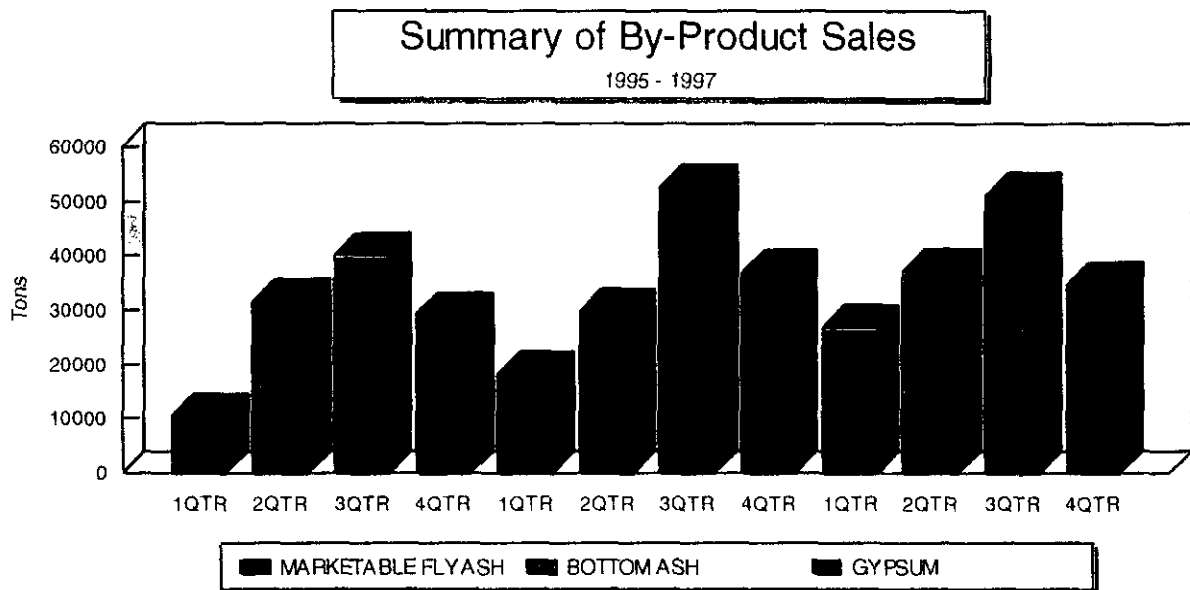
FIGURE 8.12-1



The sales of fly ash reflected the tuning of the new burners system in which much of the ash exceeded the maximum percentage (4%) of unburned carbon. As the operating experience increased with the burner system, so did the salability of flyash. The gypsum sales followed increased production due to the start-up of the Unit 1 FGD module in June 1995 and the development of contractual commitments for the gypsum. Since 100% of the bottom ash is sold as anti-skid material in the winter months, sales of bottom ash are directly related to production at the Station. Bottom ash is stored on site until the winter season when it is sold to local municipalities. The bottom ash and some gypsum were stockpiled at the solid waste disposal area while the fly ash was immediately sold to be used in concrete mixes. Sales of these combustion by-products have helped to prolong the life of the solid waste disposal facility as well as generating a revenue stream for the company.

Marketing activity during 1995 - 1996 is depicted on Figure 8.12-2.

FIGURE 8.12-2



## NOISE

The permit issued by the NYSDEC to allow construction of the Milliken CCTD project had three conditions specific to noise attenuation which included the following terms:

- No increase in residual ( $L_{90}$ ) noise levels greater than 3 A-weighted decibels is permitted at the following receptor noise monitoring stations:
  - ◊ near the closest residence on Milliken Station Road extension, located approximately 1,000 feet south of the main facility building. This residence is situated between the Conrail railroad tracks and the east shore of Cayuga Lake.

- ◇ near the closest residence north of Milliken at the end of Cuddeback Road, approximately 7,000 feet northwest of the facility.
- ◇ near the closest residence east of Milliken, 34 Milliken Station Road, approximately 5,400 feet east northeast of the facility.
- ◇ adjacent to the closest residence on the west shore of Cayuga Lake located directly across from Milliken, approximately 9,000 feet west southwest of the facility.
- ◇ at the intersection of Lake and Cuddeback Roads at the end of Algerine Road
- ◇ at the intersection of Algerine and Ludlow Roads.
- The permittee will make every reasonable effort to assure that no sounds of tonal character (e.g. hums, whines, squeals, or whistles) are clearly perceptible at annoying magnitudes at the seven receptor locations from any plant modifications that are the subject of this permit.
- Achievement of the plant design goals with respect to noise must be verified by means of a post modification noise performance test. The test will consist of measurements, per the DEIS section 3.5.5 existing ambient survey at the seven sensitive receptor locations. The verification measurements must be performed while the plant is operating at full output. The results of these tests must be sent to the NYSDEC.

Noise measurements were taken during the periods of July 20-23, 1992 and August 28-30, 1995 for baseline and project operational conditions, respectively. Measurement results for both of these periods showed that only at one location was the noise from Milliken readily discernible during both daytime and nighttime periods. At the other six receptor locations, noise was generally either not perceptible or barely perceptible. None of the seven receptor locations had noise that could be considered "of a tonal character ...clearly perceptible at annoying magnitudes." An analysis of the changes in residual ( $L_{90}$ ) noise levels at the seven monitoring stations indicates that the project operational noise did not exceed the allowable 3 dBA increase value. However, the project operational measurement program (August 28-30, 1995) was conducted during a period of significantly greater insect noise (i.e. crickets, cicadas & locusts) than existed during the baseline (July 20-23, 1992) measurements. This non-Milliken source noise was corrected for determining ultimate residual noise levels.

The project operational measurements and observations showed that any increase in residual noise levels due to the Milliken CCTD project occurred only at one monitoring location, where the increase was 1 dBA. No instances of annoying tonal noise were identified. The CCTD project has met the environmental noise criteria of the special permit conditions.

## 8.13 AIR TOXICS AND EMISSIONS CHARACTERIZATION

A comprehensive measurement program was conducted to characterize the emissions of selected trace substances from Milliken Station's Unit 2, both pre- and post-retrofit of SO<sub>2</sub>, NO<sub>x</sub> and particulate control systems. Removal efficiencies were determined for key air toxic compounds (Hg, Ni, As, Be, Cd, Cr<sup>6+</sup>, BaP, dioxins and furans). A system mass balance was developed for the metals. A utility-scale field evaluation was conducted of two promising techniques, the Ontario-Hydro and TRIS Buffer, for mercury speciation. Since EPA Method 29 and Frontier Geosciences' solid sorbent scrubber technique were already part of the post-retrofit test program scope, expanding the program to include the Ontario-Hydro and TRIS Buffer methods afforded the opportunity to compare all four mercury measurement techniques under full-scale conditions.

Prior evaluations under bench- and pilot-scale conditions comparing these four methods have shown them to be in general agreement on total mercury. EERC also operated a mercury instrumental analyzer at the FGD outlet/stack location.

The following major conclusions were drawn from the results of this test program.

### Flue Gas Testing

- The ESP was effective at removing trace elements found primarily in the solid phase from the flue gas stream with an average removal efficiency of 99.7%. Major ash elements were effectively removed by the ESP at an average efficiency of 99.9%. The FGD removed trace elements at an average removal efficiency of 36.0%, and major elements at an average efficiency of 62.6%. The ESP removal efficiency for mercury was 16.7% and the FGD removal efficiency was 59.8%. Thus, overall removals by the ESP and scrubber combined were 99.81% for trace elements found primarily in the solid phase, 99.96% for major ash elements and 66.5% for mercury.
- With the exception of selenium, ESP inlet trace and major element results are in good agreement with coal input levels. From comparisons with coal input and flyash levels, selenium results for the ESP inlet and ESP outlet are severely biased low. Severe negative matrix interferences from the high levels of sulfur found in the ESP inlet and ESP outlet samples hindered their analyses for selenium. It is now believed that sulfur interferences are the main source for the low biases associated with the selenium analytical results for Milliken Unit 2. Given the low levels of sulfur contained in the stack EPA Method 29 samples and the lack of matrix interferences encountered during analysis, the stack selenium results are considered valid.
- Reported hexavalent chromium results show that the ESP and FGD combined to remove hexavalent chromium from the flue gas stream at an efficiency of 26%. This efficiency is likely understated since the hexavalent chromium level at the stack was 4.2 times higher than the total chromium value measured by the EPA Method 29 sample train.



- The ESP removal efficiency for filterable particulate was 99.88%. ESP and coal mill upgrades for the post-retrofit test program reduced ESP outlet particulate concentrations by almost a factor of ten when compared to pre-retrofit levels. Retrofit stack particulate emissions averaged 0.007 gr/dscf or 0.014 lb/10<sup>6</sup> Btu.
- Chloride, fluoride, and sulfur were found predominantly in the gaseous phase. The FGD was effective at removing chloride, fluoride and sulfur from the flue gas with average removal efficiencies of 99.4%, 98.7% and 93.1%, respectively. Mass balance results confirm particulate and anion flue gas concentration levels.
- For PAH emissions, only naphthalene, 2-methylnaphthalene, phenanthrene, and fluoranthene were measured at the stack at levels two times higher than the analytical detection limit or notably above field blank values. No dioxin or furan isomers were detected at levels greater than twice the field blank.
- Benzene concentrations measured at the ESP outlet averaged 2.3 ppb compared to 1.1 ppb at the stack. This difference across the FGD is not considered significant. Average toluene concentrations measured at the ESP outlet of 23 ppb were significantly higher than that of 7.2 ppb measured at the stack. It is not clear whether this difference is due to actual FGD removal or if it is just an artifact of measurement uncertainty.
- Stack formaldehyde emissions averaged 9.2 ppb which was 10 times higher than ESP outlet concentrations measured at 0.9 ppb. A possible source for the additional formaldehyde is the formic acid, which can have formaldehyde as an impurity, used by the FGD process. On the other hand, stack formaldehyde sample and field blank levels were similar.
- ESP outlet SO<sub>3</sub> concentrations were 5.8 ppm compared to 4.9 ppm at the stack.
- Particle size distribution at the ESP outlet averaged 76% less than 10 microns, 56% less than 2.5 microns, and 36% less than 1 micron.

#### **Boiler/ESP and FGD Mass Balances**

- In general, material balances were excellent for the post-retrofit test program. With the exception of selenium, all trace element and anion precursor (i.e. chlorine, fluorine, and sulfur) balances fell within the acceptable range of 70-130%, with most balances between 80-115%. All major element balances fell within the acceptable range of 80-120% range, with most between 90-110%.
- Excellent FGD balances can be seen for trace and major elements (including anion precursors) existing in the ESP outlet/FGD inlet flue gas at levels above 1 lb/10<sup>12</sup>Btu. For trace elements above this level in which an FGD balance could be reported, namely arsenic and mercury, balances ranged from 92-107%; for the major elements

(excluding phosphorus and sodium), balances were consistently between 93-112%; and for the anion precursors, FGD closures fell within 97-102%.

### **Wastewater Treatment Plant Testing**

- WWTP removal efficiencies of around 75% or greater were seen for most target inorganic elements detected in the WWTP inlet stream. The treatment plant exhibited low removals for barium (12%), vanadium (46%), phosphorus (52%) and fluoride (46%). Negative or very low removals were seen for many of the water soluble elements (i.e. Ca, Mg, K, Na, Cl, S, N) suggesting that another input stream to the WWTP was a significant source of these elements, such as chemical treatment additives (e.g. lime and ferric chloride).

### **Mercury Speciation**

- For the FGD outlet/stack location, excellent agreement between the Frontier Geoscience, Ontario-Hydro and TRIS Buffer measurements can be seen for Hg(0) and Hg(II). Hg(0) results ranged from 2.45-2.94  $\mu\text{g}/\text{Nm}^3$  (excluding Method 2) and Hg(II) results ranged from 0.15-0.35  $\mu\text{g}/\text{Nm}^3$  (excluding Method 29). Good to excellent agreement exists between Frontier, Ontario-Hydro, TRIS and EPA Method 29 for total mercury with results ranging from 2.66-3.29  $\mu\text{g}/\text{Nm}^3$ .
- For the ESP outlet/FGD inlet, excellent agreement between Frontier, Ontario-Hydro, and TRIS can be seen for Hg(0) with levels ranging from 2.28-2.70  $\mu\text{g}/\text{Nm}^3$ .
- For the ESP outlet/FGD inlet, Ontario-Hydro and TRIS Buffer values are in good agreement for Hg(II); and Ontario-Hydro, TRIS and EPA Method 29 are in excellent agreement for total mercury.
- In comparison with the Ontario-Hydro and TRIS Buffer results, the EPA Method 29 mercury speciation values obtained from this test program exhibit a high bias for Hg(II), and a low bias for Hg(0).
- There is excellent agreement between the average FGD outlet/stack Hg(0) result as measured by the Semtech mercury analyzer with the other valid measurements at that location.
- FGD removal efficiencies were between 95-97% for Hg(II) (excluding EPA Method 29) and 59-65% for total mercury.
- Boiler/ESP mass balance results using Frontier Geoscience, Ontario-Hydro, TRIS Buffer, and EPA Method 29 total mercury values yielded 103%, 83%, 78%, and 85% agreement, respectively, between process streams.
- Total mercury FGD mass balance results for Frontier Geoscience, Ontario-Hydro, TRIS Buffer, and EPA Method 29 were 79%, 90%, 99%, and 93%, respectively.

## Comparison Between Pre- And Post-Retrofit Test Programs

- The most notable difference between the baseline and post-retrofit test programs is that baseline testing was conducted while firing a 100% pre-cleaned coal, while a 50/50 mix between raw and pre-cleaned coal was burned during the post-retrofit program.
- The second most notable difference is that the upgrades to the ESP and coal mills improved particulate removal efficiency from 98.95% to 99.88%, reducing ESP outlet particulate concentrations by a factor of ten.
- A 45.4% NO<sub>x</sub> reduction can be seen between the two test programs with baseline stack emissions falling from 452 ppm @ 3% O<sub>2</sub> to 247 ppm @ 3% O<sub>2</sub>.
- Notable differences in fuel composition and unit operation between the test programs include an increase in fuel sulfur from 1.9% (baseline) to 2.3% (post-retrofit), an increase in fuel ash from 7.1% to 9.6%, and a higher boiler O<sub>2</sub> during baseline testing of 3.8% versus 3.1% for the post-retrofit program.
- For the ESP inlet, notable differences between concentration levels of target elements are consistent with those seen for the coal and flyash. It should be noted that ESP inlet and ESP outlet flue gas selenium levels for both test programs severely biased low as a result of severe matrix interferences from sulfur. It should also be noted that pre-retrofit ESP outlet mercury level is biased high.
- Baseline ESP outlet particulate concentrations were reduced by 88% following the ESP and coal mill upgrades. This reduction in ESP outlet particulate levels directly corresponds to substantially reduced concentrations of trace and major elements exiting the ESP. Baseline ESP outlet trace element concentrations were reduced by 89% (excluding vapor phase elements of mercury, selenium, and anion precursors, in addition to molybdenum), and major element concentrations were reduced by 81%, for an overall reduction in trace and major elements of 86%.
- The large discrepancy between baseline and post-retrofit hexavalent chromium concentrations measured at the ESP inlet suggests that either one or both of the test programs' reported results are in error. Comparisons between mercury species flue gas results were not presented on table 5.4-5 due to concerns regarding baseline mercury speciation data validity.
- The apparent increase in ESP outlet molybdenum concentrations for the post retrofit program is not representative of any actual changes in flue gas concentration; rather it is an artifact of blank corrections since molybdenum was found at blank levels for both programs.

- The FGD in combination with the upgraded ESP reduced trace and major element emissions slightly further with an overall reduction in baseline levels of 87% for the same group of elements (with the addition of magnesium). The FGD/ESP substantially reduced baseline mercury levels by 71% and baseline chloride, fluoride, and sulfur levels by an average of 96%.
- Post-retrofit FGD outlet/stack emissions of magnesium were 53% higher than baseline emissions. This is most likely due to magnesium found within fugitive limestone particles exiting the FGD.
- For the volatile organic elements, the post-retrofit FGD and ESP upgrades combined to reduce baseline benzene emissions by 52%. However, post-retrofit FGD outlet/stack emissions of toluene and formaldehyde were 2-3 times higher than baseline emissions.

## 8.14 ECOLOGICAL RISK ASSESSMENT (TRUE EVALUATION)

The installation of the flue gas desulfurization (FGD) system at Milliken Station to control sulfur dioxide (SO<sub>2</sub>) emissions provided a unique opportunity to study the benefits that the FGD system affords to ecological receptors in the general area around the station. This was accomplished by performing an ecological risk assessment (ERA). An ERA is a process which evaluates the likelihood that adverse ecological effects are occurring or may occur as a result of exposure of ecological receptors to one or more environmental stressors. An environmental stressor is a physical, chemical, or biological factor which can induce an adverse ecological response. For the Milliken ERA, the stressor of potential concern was mercury released to the atmosphere as a result of fuel combustion at Milliken Station. The ERA characterized the potential risk posed by emissions from the Milliken Station before and after implementation of the (FGD) system. The ecological habitats and resources at or in the vicinity of the Milliken Station were characterized. These include wetlands and local water bodies, terrestrial uplands, threatened and endangered species, and important ecological features within a 50 km radius of the facility.

The evaluation used the EPRI TRUE (Total Risk and Uncertainty Evaluation) model to assess the potential for the CCTD to mitigate transferal of toxic materials from the plant site to the ambient environment. Possible transferal routes included in the study were stack emissions and contaminated water discharge streams. The risk management approach was used to demonstrate the capability of the Milliken project to mitigate health and ecological risks in the vicinity of the station. The TRUE model allows a comprehensive evaluation of the movement of hazardous pollutants into and through many environmental pathways and the manners in which humans and ecosystems may be exposed to these pollutants.

The results of the Milliken Station ERA for the pre-retrofit conditions indicated no potential ecological concern due to pre-retrofit mercury emissions from the Milliken Station for any of the aquatic or terrestrial ecological receptors. The analysis indicated that the predominant source of risk to all of the receptors is through the surface water exposure pathway, either through direct ingestion or through consumption of aquatic organisms with bioaccumulated mercury. All of the modeled media concentrations were well below screening values and the results of the food web modeling produced no Hazard Quotients (HQ's) which exceeded 1.0. For the aquatic receptors, the highest risk was due to methylmercury in the sediment, but the HQ (0.0033) was two orders of magnitude below a level of concern. For the wildlife receptors, the greatest risk was indicated for the top trophic predators in the aquatic pathway (i.e., mink (HQ = 0.15); bald eagle (HQ = 0.26)), but again below the level of concern. These results indicate that the pre-retrofit conditions do not lead to mercury emissions that have adverse impacts on the local environment.

The post-retrofit risk characterization indicated that there were no exceedances of ecotoxicological benchmarks or HQ > 1.0 for either total mercury or methylmercury for

any of the ecological receptor communities or representative species due to current emissions from the Milliken Station facility. The highest HQ's observed were for bald eagle (HQ = 0.0015) and mink (HQ = 0.0043); both of which are below potential concern. Overall, these results indicate negligible ecological risk associated with the future mercury smokestack emissions. Potential future ecological risks are approximately one order of magnitude less than those estimated for the pre-retrofit scenario.

## 8.15 BYPRODUCT UTILIZATION

The principal products covered under the byproduct utilization program included flyash, calcium chloride and gypsum.

Flyash, which is marketed as concrete additive, can be adversely affected by the installation of the Low NO<sub>x</sub> Concentric Firing System (LNCFS) and the Selective Non-Catalytic Reduction (SNCR) process. Increased carbon and ammonia concentrations can result in unmarketable ash. One objective of the By-Product Utilization Study was to analyze flyash both pre- and post- LNCFS/SNCR installation to determine impacts on the sale of ash due to changes in ash composition. Two reports were planned addressing different aspects of flyash marketability. One report was to evaluate the effects of LNCFS operation on flyash loss-on-ignition (LOI). Another was to evaluate effects of various ammonia concentrations on the marketability of flyash. The findings of the report *evaluating the effects of LNCFS operation on flyash loss-on-ignition (LOI)* are summarized below. The report of the impact of ammonia on flyash was not available at the time of publication of this Project Performance and Economics Report. When available the information will be included in a Topical Report.

Two new by-products were generated as a result of the operation of the Flue Gas Desulfurization (FGD) system: gypsum and calcium chloride brine. Separate reports for each by-product include surveys and market assessments of potential usage of these products in the United States, as well as cost assessments and design considerations associated with operating experience for their handling and conditioning. The findings of these reports are summarized below.

### IMPACT OF LOW-NO<sub>x</sub> BURNERS ON UTILIZATION OF FLY ASH

Daily data on fly ash quality and NO<sub>x</sub> emissions gathered over a five-year (1992-1996) period from the Milliken Station demonstrated that a 39% reduction in NO<sub>x</sub> was achieved using LNCFS-3 low NO<sub>x</sub> burners while producing a fly ash meeting the stringent NYDOT LOI requirement of less than 4%. During the two years directly following the installation of low-NO<sub>x</sub> burners on Unit 1 and Unit 2, 91% to 92% of the fly ash produced at Milliken was sold into the high value cement replacement market.

To allow for the installation of the LNCFS-3 system, Unit 1 was shut down March 26, 1993. The unit was started up on July 31, 1993 and evaluation testing was completed on March 15, 1994. Unit 2 went down June 17, 1994 and was put on line December 13, 1994. The burner guarantee testing for Unit 2 was completed on August 15, 1995.

This study assumed that Unit 1 burners were lined out by March 1994 and that the Unit 2 system was fined out by March 1995. The daily values of NO<sub>x</sub> emissions (30-day rolling average) for the two units were averaged individually and the monthly values used to monitor the NO<sub>x</sub> emissions from the station. The average of NO<sub>x</sub> emissions from these dates to December 1996 is 0.37 lb/MM Btu for both units (standard deviation of 0.06 for

Unit 1 and 0.08 for Unit 2). Based on a NO<sub>x</sub> emissions rate of 0.61 lb/MM Btu before burner conversion, the results demonstrate that the LNCFS-3 burner system allowed Milliken to achieve a 39% reduction in NO<sub>x</sub> over extended periods (34 months for Unit 1 and 22 months for Unit 2) of time.

It was assumed that the ash property most influenced by the use of low NO<sub>x</sub> burners was the LOI. To confirm this assumption, two ash samples were obtained, each sample represented a two-day period before and after the low NO<sub>x</sub> burner conversion. The samples were taken from Unit 2 when firing Bailey coal. The two ash samples were processed through the suite of tests required by the ASTM C618 protocol. Both fly ash samples met all ASTM specifications for use as a mineral admixture in Portland cement concrete. Except for particle size, there was no substantial difference in the chemical compositions or the physical properties of the two fly ash samples.

In the recent past, the fly ash produced at Milliken met the NYDOT specification for cement replacement, a high value utilization option. NYDOT's specification requires ash to have an LOI value of less than 4% in addition to passing the ASTM C-316 protocol. This LOI requirement is one of the most stringent in the USA.

The LOI value of daily samples taken by the ash marketer was used as the data source for the long-term fly ash quality comparison. This specific LOI value governed what the ash marketer would do with a particular day's ash and, therefore, represents the final word on ash quality. An LOI value of 4% or higher would dictate that the ash go to the landfill, while a value of 4% or less would allow it to go to the product silo. The daily LOI values were averaged by month. The LOI monthly average was the variable used in this study to show the fluctuation of fly ash quality with time.

The LOI monthly averages for the fly ash from Unit 1 and Unit 2 from January 1992 through December 1996 were tabulated. Based on the dates assumed for lined out burner conditions in the NO<sub>x</sub> emission analysis, the tabulated LOI values and standard deviations demonstrate that "on spec" fly ash LOI < 4% was produced after the LNCFS-3 system was installed and tuned.

Sales information is the ultimate measure for fly ash quality. The fly ash sales were in excess of 90% following the burner conversion confirming the conclusion that the sales were not adversely impacted by installing the LNCFS-3 system.

## **CALCIUM CHLORIDE MARKET OPPORTUNITIES**

The purpose, of the report entitled "Calcium Chloride Marketing Opportunities: a Flue Gas Desulfurization Waste Stream Alternative" is to help utility decision makers assess the CaCl<sub>2</sub> industry in North America, with a view towards identifying potential market opportunities for selling CaCl<sub>2</sub>, which can be produced by upgrading FGD waste streams. The report begins with a section on the sources of CaCl<sub>2</sub> and production methods worldwide. It then describes in detail the major worldwide uses for CaCl<sub>2</sub>. Next, the



report gives the various product forms and specifications. The final section contains details on  $\text{CaCl}_2$  consumption and pricing in North America.

The report draws the following conclusions:

- There are some limited (but not guaranteed) niche opportunities for utilities to sell byproduct  $\text{CaCl}_2$  in the United States (as opposed to incurring the cost of disposal).
- At a minimum, utilities should plan to produce  $\text{CaCl}_2$  brines which are at least 32%  $\text{CaCl}_2$  by weight. The selling price established by the utilities will range from \$0 (with the value of avoiding disposal costs) to the existing market price. Additional details are provided in Section 6 of the report.
- $\text{CaCl}_2$  is produced at 16 facilities within North America. Output from 9 of these facilities is purchased/marketed by four companies (Dow Chemical, Tetra Chemical, General Chemical, and Hill Brothers), representing approximately 90% of the total industry capacity in North America. Conservatively, U.S. production capacity exceeds demand by approximately 40%.
- $\text{CaCl}_2$  is an undifferentiated commodity chemical with well-established, mature markets. The principal uses/markets for  $\text{CaCl}_2$  in North America include: roadway maintenance (dust control and de-icing), 60%; industrial (coal thawing, refrigerant, wastewater treatment), 20%; oil and gas well drilling, 5%; concrete "setting" accelerant, 5%; tire ballast, 3%; and miscellaneous (de-inking, food, desiccant, etc.), 7%. Historical and projected growth of these markets is less than 2% through 1997.
- $\text{CaCl}_2$  is also produced in Europe and Asia for similar uses/markets as those in the United States and North America.
- Much of the  $\text{CaCl}_2$  sold is in the form of 32%-38% brine, which is prohibitively expensive to transport over extended distances. Thus, while excess  $\text{CaCl}_2$  production capacity does exist, utilities can capitalize on niche market opportunities if they produce by-product  $\text{CaCl}_2$  in an area close to the market and/or centralized distribution point, and at a delivered price competitive with current suppliers.
- In this case, suppliers are defined to include both the manufacturers of  $\text{CaCl}_2$ , as well as the network of distributors (which is the way that most  $\text{CaCl}_2$  is sold).

If a utility is considering installing an FGD process and associated equipment to generate by-product  $\text{CaCl}_2$  it should identify and contact the major manufacturer(s) and distributors serving that area. Cost and ability to deliver the product on an acceptable schedule are critical to marketability. Intermediate storage of byproduct may be required in order to serve the identified market.

## THE GYPSUM INDUSTRY AND FGD GYPSUM UTILIZATION

As utilities search for the most economical approach for implementing the Clean Air Act provisions, waste disposal costs will play a big role in their decision. It quickly becomes apparent to the utility that a solution producing usable by-products can provide potential opportunities which should be considered. Although there is considerable R&D work being done to make beneficial use of solid desulfurization wastes, currently, there is only one material which qualifies as a product with a large existing market. That material is gypsum.

Gypsum is a naturally occurring mineral which has a current demand in the United States of 26 million short tons per year. Included in this demand is a chemical (by-product) gypsum market of about 0.75 million short tons per year in the United States. About half of the chemical gypsum is produced in FGD units. Gypsum is not the only solution for utilities' disposal problems, but it is one of the most practical under current conditions.

NYSEG, along with R.A.K Associates, ORTECH and CONSOL developed a comprehensive document detailing the technical and economic aspects of the gypsum industry. Published by EPRI (EPRI TR-102652, Dated February 1994) and entitled "The Gypsum Industry and Flue Gas Desulfurization (FGD) Gypsum Utilization: A Utility Guide", the purpose of this report is to provide power utilities with a technical and economic perspective of the gypsum industry in North America, with a view to the factors affecting the utilization of flue gas desulfurization (FGD) gypsum in traditional applications. A literature search including discussions with consultants was completed on all phases of the North American gypsum industry from production through marketing. European and Asian experiences and markets are also discussed.

The reports concludes that gypsum is not an all-encompassing solution to the waste issues created for utilities trying to comply with the Clean Air Act. However, the potential for producing such a high quality raw material as a scrubber by-product presents potential opportunities which each utility must consider in relation to its own local environment.

The technical feasibility of substituting FGD gypsum for natural gypsum in traditional applications including wallboard and cement manufacture, as an agricultural soil conditioner/supplement, and in the preparation of both building and specialty plasters, has been demonstrated. With respect to the wallboard and cement industry, the physical form (particle size distribution, moisture content) is the most significant difference relative to natural rock, and may require modifications to existing materials handling equipment. In some cases, agglomeration and/or drying of the finer FGD material may be necessary by either the utility or the end user. However, as gypsum consumers become more experienced with FGD gypsum, they can learn to handle the material with only minimal additional processing by the producer (i.e., adequate dewatering). Chemical differences can be overcome and, in some cases, may be beneficial (i.e., purity and color). Effective

techniques can reduce chlorides, the impurity of most concern, to levels where they do not affect processes, products or applications.

Economically, the production of a salable FGD gypsum does not add substantial costs to the utility striving to comply with the Clean Air Act. Local environmental considerations will be a factor in determining whether the production of high quality FGD gypsum is economically viable (i.e., available disposal sites and costs). As disposal costs rise, the use of FGD gypsum will be most dependent on distance and associated transportation costs between the FGD gypsum producer and consumer, as well as localized availability of cheap, natural gypsum of acceptable quality.

Wallboard and cement manufacturers are the largest consumers of gypsum, and are therefore the most obvious target markets for FGD gypsum producers. However, it is possible that in the near future, with the increasing numbers of utilities that will be producing high quality gypsum, an oversupply may exist.

Agricultural applications have been successfully demonstrated, especially in the peanut industry. The growth potential for this market could be high if yield advantages for a variety of crops can be demonstrated. Currently, this market is geographically limited to the more southern regions of the United States. However, research is currently being conducted in other regions of the United States which could potentially expand this market.

Other potential markets include specialty plasters, fillers, alternative building products and plasters for use in mining mortars. Specialty plasters would be particularly attractive if they can be produced at a competitive cost while maintaining quality.

With the possibility of oversupply in the obvious markets, it would be advantageous to the utilities to undertake research, market and product development activities to enhance the sales potential for their material in alternative markets.

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# **APPENDIX A EQUIPMENT LIST**

**APPENDIX A  
MAJOR EQUIPMENT LIST**

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2A.04 350	FGD Chimney & Flues	1	0	416,140 ACFM Per Flue	(2) 12' Diameter Flues; (1) 8' Diameter Bypass	Steel Shell (2) FRP Flues (1) Carbon Steel Bypass	International Chimney
1.2B.02 263	Limestone Day Storage Bins BI340-A-B	2	0	320 Tons Each	Vertical Cylindrical	Lined Carbon Steel	FMC
1.2B.02 421	Ball Mill WBM-113 & 213	2	0	24 TPH	Wet Horizontal	Carbon Steel	Fuller
1.2B.02 421	Weigh Feeder BFU-113 & 213	1	1	24 Tons Per Hour	Gravimetric	Carbon Steel Housing, Rubber Belts	Stock
1.2B.02 421	Mill Hydroclone Set - HCY-113 & 213	1	1	865 GPM	90%-325 Mesh & 90%-170 Mesh	Rubber Lined Carbon Steel	Krebs
1.2B.02 421	Mill Slurry Tank TK-113 & 213	1	1	5,000 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	Fuller
1.2B.02 421	Mill Slurry Tank Agitator AG-113 & 213	1	1	7.5 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 421	Mill Slurry Pumps PP-113A & B, PP-213A & B	1	3	865 GPM 100' TDH, 50 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 423	Fresh Slurry Feed Tank, TK-104 & 204	2	0	64,000 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	Fisher
1.2B.02 423	Fresh Slurry Feed Tank Agitator, AG-104 & 204	1	1	5 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.02 423	Fresh Slurry Forwarding Pump PP-104A&B, 204A&B	1	3	550 GPM 83' TDH, 25 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 432	Centrifuge Feed Tanks, TK-111,211	1	1	3,500 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	Sterling Boiler
1.2B.02 432	Centrifuge Feed Tank Agitators AG-111,211	1	1	1 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 432	Centrifuges DFS-111A & B, 211A & B	3	1	27 Tons Per Hour	Vertical Basket Centrifuges	Rubber Lined Carbon Steel	Krauss
1.2B.02 432	Centrifuge Feed Pumps, PP-111,211	1	1	1,000 GPM 60' TDH, 30 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 433	Primary Hydroclones, HCY-101, 201	1	1	1,050 GPM	6 Cyclones Per Half; 5 Operating At Once	Rubber Lined Carbon Steel	Warman
1.2B.02 433	Secondary Hydroclones, HCY-102, 202	1	1	300 GPM	6 Cyclones; 5 operating at once	Rubber Lined Carbon Steel	Warman
1.2B.02 433	Secondary Hydroclone Feed Tank Agitators, AG-102,202	1	1	1 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 433	Secondary Hydroclone Feed Pumps, PP-102,202	1	1	300 GPM 81' TDH, 15 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 433	Secondary Hydroclone Feed Tanks, TK-102,202	1	1	3,500 GALS	Vertical Cylindrical	Vinyl Ester Lined Carbon Steel	Sterling Boiler
1.2B.02 434	Filtrate Return Pumps, PP-101, 201	1	1	1000 GPM 69' TDH, 40 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.02 434	Filtrate Tank Agitator, AG-101, 201	1	1	1.5 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 434	Filtrate Tanks, TK-101 & 201	1	1	20,750 GALS	Vertical Cylindrical	Vinyl Ester Lined Carbon Steel	Fisher
1.2B.02 435	Clarified Water Tanks, TK-107 & 207	1	1	63,400 GALS	Vertical Cylindrical	Vinyl Ester Lined Carbon Steel	Fisher
1.2B.02 435	Clarified Water Tank Agitators, AG-107, AG-207	1	1	3 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 435	Blowdown Pumps, PP-108, 208	1	1	35 GPM 48' TDH, 5 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 435	Clarified Water Pumps, PP-107, 207	1	1	400 GPM 120' TDH, 25 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 461	Slurry Recycle Pumps, ARP 100A-G, 200A-G	10	4	10,500 GPM 80/90/100/110 TDH 350/400/450/500HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	GIW
1.2B.02 462	Oxidation Blowers, BW-101,201,301	2	1	5,000 ACFM 500 HP	Centrifugal; Includes Sound Enclosure	Carbon Steel	Turblex
1.2B.02 462	Absorber Agitator, AG-100A-E, 200A-E	8	2	25 HP	Side Mounted	Alloy Shafts & Impellers	Ekato
1.2B.02 463	Process Water Tank	1	0	27,000 GALS	Vertical Cylindrical	Coated Carbon Steel	Fisher

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material or Construction	Vendor
		In Use	Spare				
1.2B.02 463	Process Water Pump, PP-103, 203, 303	2	1	700 GPM 273' TDH, 75 HP	Horizontal Centrifugal Flow	Carbon Steel	Goulds
1.2B.02 464	Absorber Slurry Drain Tank, TK-305	1	0	300,000 GALS	Vertical Cylindrical	Mastic Lined Concrete	San-Con
1.2B.02 464	Absorber Slurry Drain Tank Agitator, AG-305	1	0	20 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.02 464	Absorber Slurry Drain Pumps, PP-305A & PP-305B	1	1	500 GPM 73' TDH, 20 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 465	Bleed Pumps, PP-112A&B, 212A&B	2	2	500 GPM 133' TDH, 40 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.02 466	Formic Acid Tank, AST-301	1	0	5,000 Gal.	Vertical Cylindrical	316L SS	Sterling Boiler
1.2B.02 466	Formic Acid Metering Pumps, AMP-101,201,301	2	1	6.2 GPM 60 PSI, .5 HP	Metering Pumps Diaphragm Type	316L SS	Milton Roy
1.2B.02 467	Mist Eliminator Wash Spray Nozzles, WVN-025	56	0	10 GPM	Full Cone	Polypropylene	Bete
1.2B.02 467	Quench Water Spray Nozzles, EQN-0375,QNS-025	80	0	2 GPM	Pig Tail	Hastelloy	Lechler
1.2B.02 467	Recirc Spray Cocurrent Section Spray Nozzles	106	0	875 GPM	Pig Tail	Silica Carbon	Lechler
1.2B.02 467	Recirc Spray Counter Current Spray Nozzles	159	0	438 GPM	Pig Tail	Silica Carbon	Lechler

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.02 471	Mist Eliminators, VME-101, 102, 201 & 202	4	0	416,000 ACFM	Chevron Vertical Flow 1st & 2nd Stage Mist Eliminators	FRP Polypropylene	Munters
1.2B.03 260	Limestone Handling Equipment, Including Belt Conveyors, CON340A, B; Scale, Separator, Gates, Chutes, etc.	2	0	100 Ton/Hour Each	200 Ton/Hour Total Capacity	Carbon Steel	FMC
1.2B.03 260	Vibrating Bin Discharger	1	1	100 Ton/Hour 3 HP	12' Diameter Inlet 2' Diameter Outlet 60° Conical Slope	Steel Neoprene	Kinergy
1.2B.03 260	Dust Collection System 1DC-2, 1BVF-1, 1BVF-2, 1DC-1	4	0	161 Sq. Ft. 484 Sq. Ft. 150 Sq. Ft.	Insertable Venting Filters	Steel Polyester	DCE
1.2B.05 441	Equalization Tank, TK-320	1	0	16,000 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	FMC
1.2B.05 441	Desaturation Tank, TK-321	1	0	3,225 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Heavy Metal Tank, TK-322	1	0	800 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Coagulation Tank, TK-323	1	0	420 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Ferric Chloride Tank, TK-325	1	0	185 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Organo Sulfide Tank, TK-326	1	0	132 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Lime Slurry Tank, TK-327	1	0	575 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI



Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.05 441	Sludge Holding Tank , TK-328	1	0	24,000 GALS	Vertical Cylindrical	Rubber Lined Carbon Steel	IDI
1.2B.05 441	CPR Sludge Holding Tank , TK-329	1	0	24,000 GALS	Vertical Cylindrical	Carbon Steel	IDI
1.2B.05 441	FGD Filtrate Tank , TK-330	1	0	3,500 GPM	Vertical Cylindrical	Carbon Steel	IDI
1.2B.05 441	CPR Filtrate Tank , TK-331	1	0	3,500 GPM	Vertical Cylindrical	Carbon Steel	IDI
1.2B.05 441	Equalization Tank Agitator, AG-320	1	0	3 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	pH Elevation/Saturation Tank Agitator, AG-321	1	0	2 HP	Top Mounted	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Heavy Metal Precip. Tank Agitator, AG-322	1	0	0.5 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	Coagulation Tank Agitator, AG-323	1	0	0.5 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	Densadeg Reactor Agitator, AG-324	1	0	2 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	Lime Slurry Tank Agitator, AG-327	1	0	1 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	Sludge Holding Tank Agitator, AG-328	1	0	10 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 441	Filter Press, FLP-328	1	0	5 HP		Carbon Steel	IDI
1.2B.05 441	Ferric Chloride Feed Pumps, PP- 325A,B	1	1	1.4 HP, 1.4 Amp	Metering Pump	Polypropylene	Promient

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.05 441	Organosulfide Feed Pumps, PP-326A,B	1	1	0.6 LPH, 1.4 Amp	Metering Pump	Polypropylene	Promient
1.2B.05 441	Forward Feed Pumps, PP-322A, B	1	1	30 GPM 30' TDH, 2 HP	Horizontal Centrifugal Flow	Rubberized Cast Iron	IDI
1.2B.05 441	Sludge Waste Pumps, PP-323A, B	1	1	50 GPM 70' TDH, 5 HP	Positive Displacement	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Sludge Recycle Pumps, PP324A, B	1	1	20 GPM 70' TDH, 2 HP	Positive Displacement	Rubber Lined Carbon-Steel	IDI
1.2B.05 441	Filter Press Feed Pump, PP-328	1	0	90 GPM 225 PSI, 20 HP	Positive Displacement	Rubber Lined Carbon Steel	IDI
1.2B.05 441	Lime Slurry Pump Skid, PP-327	1	0	70 GPM 50' TDH, 3 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.05 441	FGD Filtrate Pump, PP-330	1	0	70 GPM 35' TDH, 5 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.05 441	CPR Filtrate Pump, PP-331	1	0	250 GPM 67' TDH, 7.5 HP	Horizontal Centrifugal Flow	Rubber Lined Carbon Steel	BGA
1.2B.05 441	Densadeg Reactor, RE-324	1	0	700 GAL		Rubber Lined Carbon Steel	IDI
1.2B.05 441	Densadeg Thickener, TH1-320	1	0	30,000 GAL		Rubber Lined Carbon Steel	IDI
1.2B.05 441	Densadeg Scraper, SCR-320	1	0	1 HP	Top Mounted	Rubber Lined Carbon Steel	IDI
1.2B.05 443	Evaporator/Brine Concentrator, EV-311	1	0	30 GPM 4,000 Gal.	Falling Film Evaporator	Titanium	RCC

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.05 443	Brine Concentrator Storage Tank Agitator, AG-311	1	0	2 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 443	Brine Concentrator Storage Tank, TK-311	1	0	19,000 GALS	Vertical Cylindrical	Vinyl Ester Lined Carbon Steel	RCC
1.2B.05 443	Product Tank, TK-316	1	0	4,700 GALS	Vertical Cylindrical	FRP	ERSHIGS
1.2B.05 443	Brine Concentrator Feed Tank Agitator, AG-312	1	0	0.25 HP	Top Mounted	Rubber Lined Carbon Steel	Lightnin
1.2B.05 443	Product Tank Agitator, AG-316	1	0	1 HP	Top Mounted	Hastelloy	Lightnin
1.2B.05 443	Vapor Compressor W/ Sound Enclosure, CM-311	1	0	4,139 ACFM 450 HP	Centrifugal	Titanium/316 SS	Ingersoll- Rand
1.2B.05 443	FGD Blowdown Transfer Pumps, PP-311A, B	1	1	30 GPM 3 HP	Horizontal Centrifugal Flow	Monel	Goulds
1.2B.05 443	Brine Concentrator Primary Feed Pumps, PP-312A, B	1	1	40 GPM 7.5 HP	Horizontal Centrifugal Flow	Monel	Goulds
1.2B.05 443	Acid Tank, TK-313	1	0	55 GPM	Vertical Cylindrical	PVDF	
1.2B.05 443	Scale Inhibitor Feed Tank, TK-312	1	0	55 GPM	Vertical Cylindrical	Polyethylene	
1.2B.05 443	Brine Concentrate Feed Tank, TK- 315	1	0	300 GPM	Vertical Cylindrical	FRP	Chromium Proof Corp.
1.2B.05 443	Distillate Tank, TK-315	1	0	200 GPM	Vertical Cylindrical	316 SS	Chomithon

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.05 443	Primary Heat Exchanger, HE-311	1	0	30 GPM Feed 88° AT Feed 106° AT Distillate	Plate Type	Titanium GR1	APV Crepaco
1.2B.05 443	Secondary Heat Exchanger, HE-312	1	0	30 GPM Feed 61° AT Feed 74° AT Distillate	Plate Type	Titanium GR1	APV Crepaco
1.2B.05 443	Deaerator Tower, DA-311	1	0	30 GPM	Vertical Cylindrical	FRP Polypropylene	Chromium Proof Corp.
1.2B.05 443	Seed Hydroclone	1	0	20 GPM	PC2-1597	Kynar/Ceramic	Krebs
1.2B.05 443	Scale Inhibitor Pumps, PP-314A,B	1	0	.036 GPH 120 V Solenoid	Metering Pump	Polypropylene	Promient
1.2B.05 443	Acid Pumps, PP-313A,B	1	0	.084 GPH 120 V Solenoid	Metering Pump	Teflon	Promient
1.2B.05 443	Seed Recycle Pump, PP-318	1	0	20 GPM 3 HP, 75 PSI	Horizontal Centrifugal Flow	Ferrallium 255	Goulds
1.2B.05 443	Underflow Pump, PP-319	1	0	30 GPM	Air Operated	Hastelloy C	Wilden Pumps
1.2B.05 443	Recirculation Pump, PP-317	1	0	1820 GPM 30 HP, 28 PSI	Horizontal Centrifugal Flow	Ferrallium 255	Goulds
1.2B.05	B,C. Secondary Feed Pumps, PP-316A,B	1	0	30 GPM 7.5 HP, 54 PSI	Horizontal Centrifugal Flow	Monel	Goulds
1.2B.05	Distillate Pumps, PP-315A,B	1	0	30 GPM 15 HP, 85 PSI	Horizontal Centrifugal Flow	316 SS	Goulds

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
1.2B.06 270	Gypsum Handling Equipment, Including Belt Conveyors, & CON-341A, B, C, D, E	3	2	100 Ton/Hour Each	200 Ton Total Capacity	Carbon Steel	FMC
1.2B.15 472	Unit 1 & Unit 2 ID Fans	4	0	295,000 ACFM 2,000 HP	Single Speed W/Backward Curve Blades; Induced Air Cooled Bearings	Carbon Steel	Buffalo Forge
1.2B.15 475	Absorber Inlet Isolation Dampers	2	0	1,616,646 Lb/Hr 550,000 ACFM (Each)	Guillotine	Carbon Steel	Effox
1.2B.15 475	Absorber Crossover Isolation Dampers	2	0	1,616,646 Lb/Hr 550,000 ACFM (Each)	Double Louver	Carbon Steel	Effox
1.2B.15 475	ID Fan Outlet Isolation Dampers	4	0	808,300 Lb/Hr 253,000 ACFM (Each)	Double Louver	Carbon Steel	Effox
1.2B.15 475	Bypass Control Damper	1	0	1,550,000 Lb/Hr 483,500 ACFM	Modulating Double Louver	Carbon Steel	Effox

Item No.	Item Name	Number		Unit Capacity	Design Conditions	Material of Construction	Vendor
		In Use	Spare				
<b>BALANCE OF PLANT</b>							
1.2A&B.09&1 CM-101 A - H	Coal Mills & Balance of Job	8	0	36,800 lb/hr	Pressurized mill with Dynamic Classifier	Alloy hardened and ceramic lined wear parts	Riley-Stoker
1.2B.12 HP-001	Heat Pipe	2	0	250° F Gas Outlet		Carbon Steel with Alloy Tubes	ABB Air Pre-heater
1.2B.11 UI-200	SNCR	1	0			Leased Equipment	NALCO
1.2A&B.07&08 ES-101 A - D	ESP Modifications	2	0	99.6%	Rigid Electrode	Carbon Steel	BELCO



**APPENDIX B**  
**MAJOR EQUIPMENT COSTS BY AREA**



**APPENDIX B  
MAJOR EQUIPMENT COSTS  
AREA NO. 100: RAW MATERIAL RECEIVING & HANDLING SYSTEM**

Area No.	Item No.	Item Name	Cost/Unit							No. of Units	Total Cost	Year
			F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field Labor	Total			
100	1.2B.02 263	Limestone Day Storage Bins	\$75,380	Exempt	Included	\$0	\$57,082	W/Field Labor	\$132,462	2	\$264,923	1994
100	1.2B.02 421	Ball Mill WBM	\$1,215,706	Exempt	Included	\$0	\$164,500	W/Field Labor	\$1,380,206	2	\$2,760,411	1994
100	1.2B.02 421	Weigh Feeder	W/Ball Mill	Exempt	Included	\$0	\$5,000	W/Field Labor	\$5,000	2	\$10,000	1994
100	1.2B.02 421	Mill Hydroclone Set	W/Ball Mill	Exempt	Included	\$0	\$8,000	W/Field Labor	\$8,000	2	\$16,000	1994
100	1.2B.02 421	Mill Slurry Tank	W/Ball Mill	Exempt	Included	\$0	\$8,754	W/Field Labor	\$8,754	2	\$17,508	1994
100	1.2B.02 421	Mill Slurry Tank Agitator	\$12,547	Exempt	Included	\$0	\$3,000	W/Field Labor	\$15,547	2	\$31,093	1994
100	1.2B.02 421	Mill Slurry Pumps,	\$27,073	Exempt	Included	\$0	\$6,000	W/Field Labor	\$33,073	4	\$132,292	1994
100	1.2B.03 260	Limestone Handling Equipment: Incl. Belt Conveyors, Scales, Separator, Gates, Chutes	\$341,559	Exempt	Included	\$0	\$234,565	W/Field Labor	\$576,124	2	\$1,052,243	1994
100	1.2B.03 260	Vibrating Bin Discharger	\$14,636	Exempt	Included	\$0	\$17,539	W/Field Labor	\$32,175	2	\$64,350	1994
100	1.2B.03 260	Dust Collection System	\$13,432	Exempt	Included	\$0	\$1,368	W/Field Labor	\$14,800	4	\$59,200	1994
100	1.2B.03	Balance of Job - Mechanical	\$0	Exempt	Included	\$10,000	\$219,890	W/Field Labor	\$229,890	1	\$229,890	1994
100	1.2B.03	Balance of Job - Electrical	\$0	Exempt	Included	\$57,140	\$106,248	W/Field Labor	\$163,388	1	\$163,388	1994
100	1.2B.03	Balance of Job -Civil/Limestone Storage-Pond & Discharge Structure	\$0	Exempt	Included	\$184,188	\$317,120	W/Field Labor	\$501,308	1	\$501,308	1994

- A. Subtotal Installed Cost \$5,303,000
- B. Retrofit Costs Included
- C. Process Contingency Included
- D. Total Installed Equipment Cost \$5,303,000

APPENDIX B  
MAJOR EQUIPMENT COSTS  
AREA NO.800: SO<sub>2</sub> REMOVAL SYSTEM

Area No.	Item No.	Item Name	Cost/Unit										No. of Units	Total Cost	Year
			F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field Labor	Total	Field Labor	With Equipment	With Equipment			
800	1.2B.02 423	Fresh Slurry Feed Tank, (Incl. Tank Lining)	\$0	Exempt	Included	\$99,755	\$88,840	W/Field Labor			\$188,595	1	\$188,595	1993	
800	1.2B.02 423	Fresh Slurry Feed Tank Agitator,	\$17,294	Exempt	Included	\$0	\$3,000	W/Field Labor			\$20,294	1	\$20,294	1994	
800	1.2B.02 423	Fresh Slurry Forwarding Pumps	\$12,310	Exempt	Included	\$0	\$4,000	W/Field Labor			\$16,310	2	\$32,620	1994	
800	1.2A.04 461	Absorber Modules	\$2,795,225	Exempt	Included	With Equipment	With Equipment	Equipment			\$2,795,225	1	\$2,795,225	1994	
800	1.2B.02 461	Slurry Recycle Pumps	\$112,523	Exempt	Included	\$0	\$15,714	W/Field Labor			\$128,237	8	\$1,025,897	1994	
800	1.2B.02 462	Oxidation Blowers	\$213,278	Exempt	Included	\$0	\$13,278	W/Field Labor			\$226,556	3	\$679,868	1994	
800	1.2B.02 462	Absorber Agitators	\$42,144	Exempt	Included	\$0	\$4,445	W/Field Labor			\$46,589	9	\$419,300	1994	
800	1.2B.02 464	Absorber Slurry Drain Tank	\$0	Exempt	Included	\$271,883	Included W/Material	W/Field Labor			\$271,883	1	\$271,883	1994	
800	1.2B.02 464	Absorber Slurry Drain Tank Agitator	\$36,835	Exempt	Included	\$0	\$8,000	W/Field Labor			\$44,835	1	\$44,835	1994	
800	1.2B.02 464	Absorber Slurry Drain Pumps	\$16,112	Exempt	Included	\$0	\$5,000	W/Field Labor			\$21,112	2	\$42,224	1994	
800	1.2B.02 465	Bleed Pumps	\$15,405	Exempt	Included	\$0	\$5,666	W/Field Labor			\$21,072	3	\$63,215	1994	
800	1.2B.02 466	Formic Acid Tank	\$26,103	Exempt	Included	\$0	\$5,000	W/Field Labor			\$31,103	1	\$31,103	1994	
800	1.2B.02 466	Formic Acid Metering Pumps	\$6,948	Exempt	Included	\$0	\$333	W/Field Labor			\$7,281	3	\$21,843	1994	
800	1.2B.02 467	Mist Eliminator Wash Spray Nozzles	\$37	Exempt	Included	\$0	\$36	W/Field Labor			\$73	56	\$4,099	1994	
800	1.2B.02 467	Quench Water Spray Nozzles	\$90	Exempt	Included	\$0	\$50	W/Field Labor			\$140	80	\$11,200	1994	
800	1.2B.02 467	Recirc Spray Occurent Section Spray Nozzles	\$501	Exempt	Included	\$0	\$168	W/Field Labor			\$669	85	\$58,546	1994	

**APPENDIX B  
MAJOR EQUIPMENT COSTS  
AREA NO.800: SO<sub>2</sub> REMOVAL SYSTEM**

Area No.	Item No.	Item Name	Cost/Unit							No. of Units	Total Cost	Year
			F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field Labor	Total			
800	1.2B.02 467	Recirc Spray Counter Current Spray Nozzles	\$388	Exempt	Included	\$0	\$157	W/Field Labor	\$545	159	\$86,676	1994
800	1.2B.02 471	Mist Eliminators	\$243,239	Exempt	Included	\$0	\$20,000	W/Field Labor	\$160,970	2	\$548,478	1994
800	1.2B.03	Balance of Job - Mechanical	\$0	Exempt	Included	\$518,270	\$2,151,409	W/Field Labor	\$2,669,679	1	\$2,669,679	1994
800	1.2B.03	Balance of Job - Electrical	\$0	Exempt	Included	\$0	\$138,778	W/Field Labor	\$138,778	1	\$138,778	1994
800	1.2B.03	Balance of Job - Civil	\$0	Exempt	Included	\$35,752	\$30,090	W/Field Labor	\$65,842	1	\$65,842	1994

- A. Subtotal Installed Cost \$9,220,000
- B. Retrofit Costs Included
- C. Process Contingency Included
- D. Total Installed Equipment Cost \$9,220,000

**APPENDIX B  
MAJOR EQUIPMENT COSTS  
AREA NO. 1100: FLUE GAS HANDLING SYSTEM**

Area No.	Item No.	Item Name	Cost/Unit										Total Cost	Year
			F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total	No. of Units				
1100	1.2A.04 350	FGD Chimney & Flues	\$892,440	Exempt	Included	\$611,232	\$1,011,547	W/Field Labor	\$2,485,150	1	\$2,485,150	1994		
1100	1.2B.15 472	Unit 1 & Unit 2 ID Fans	\$304,384	Exempt	Included	\$0	Included W/Ductwork	W/Field Labor	\$304,384	4	\$1,217,535	1994		
1100	1.2B.15 475	FGD Dampers	\$70,915	Exempt	Included	\$5,667	\$12,167	W/Field Labor	\$88,749	9	\$798,744	1993		
1100	1.2B.15 307	Ductwork & Insulation	\$0	Exempt	Included	\$1,720,558	\$1,437,675	W/Field Labor	\$3,158,233	1	\$3,158,233	1994		
1100	1.2B.15	Balance of Job - Civil/Structural	\$0	Exempt	Included	\$589,527	\$441,520	W/Field Labor	\$1,031,047	1	\$1,031,047	1994		
1100	1.2B.15	Balance of Job - Mechanical	\$0	Exempt	Included		\$0	W/Field Labor	\$80,000	1	\$80,000	1994		
1100	1.2B.15	Balance of Job - Electrical/I&C	\$0	Exempt	Included	\$0	\$37,600	W/Field Labor	\$37,600	1	\$37,600	1994		

A. Subtotal Installed Cost      \$8,808,000  
 B. Retrofit Costs                      Included  
 C. Process Contingency              Included  
 D. Total Installed Equipment Cost    \$8,808,000

APPENDIX B  
MAJOR EQUIPMENT COSTS  
AREA NO. 1300: BY-PRODUCT PROCESSING & HANDLING SYSTEM

Area No.	Item No.	Item Name	Cost/Unit										No. of Units	Total Cost	Year
			F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total						
1300	1.2B.02 432	Centrifuge Feed Tanks	\$14,571	Exempt	Included	\$0	\$5,400	W/Field Labor	\$19,971	1	\$19,971	1994			
1300	1.2B.02 432	Centrifuge Feed Tank Agitators, (Incl. Rubber Blades)	\$6,047	Exempt	Included	\$0	\$2,000	W/Field Labor	\$8,047	1	\$8,047	1994			
1300	1.2B.02 432	Centrifuges	\$355,542	Exempt	Included	\$0	\$20,000	W/Field Labor	\$375,542	4	\$1,502,170	1994			
1300	1.2B.02 432	Centrifuge Feed Pumps	\$17,603	Exempt	Included	\$0	\$6,000	W/Field Labor	\$23,603	2	\$47,206	1994			
1300	1.2B.02 433	Primary Hydroclones	\$55,986	Exempt	Included	\$0	\$6,000	W/Field Labor	\$61,986	1	\$61,986	1994			
1300	1.2B.02 433	Secondary Hydroclones	\$18,975	Exempt	Included	\$0	\$6,000	W/Field Labor	\$24,975	1	\$24,975	1994			
1300	1.2B.02 433	Sec Hydroclone Feed Tank Agitators	\$8,256	Exempt	Included	\$0	\$1,000	W/Field Labor	\$9,256	1	\$9,256	1994			
1300	1.2B.02 433	Secondary Hydroclone Feed Pumps	\$10,363	Exempt	Included	\$0	\$3,000	W/Field Labor	\$13,363	2	\$26,726	1994			
1300	1.2B.02 433	Secondary Hydroclone Feed Tanks, (Incl. Liner)	\$0	Exempt	Included	\$22,258	\$5,000	W/Field Labor	\$27,258	1	\$27,258	1994			
1300	1.2B.02 434	Filtrate Return Pumps	\$26,310	Exempt	Included	\$0	\$5,000	W/Field Labor	\$31,310	2	\$62,620	1994			
1300	1.2B.02 434	Filtrate Tank Agitator	\$11,339	Exempt	Included	\$0	\$2,000	W/Field Labor	\$13,339	1	\$13,339	1994			
1300	1.2B.02 434	Filtrate Tanks, (Incl. Liner)	\$0	Exempt	Included	\$43,179	\$23,000	W/Field Labor	\$66,179	1	\$66,179	1993			
1300	1.2B.02 435	Clarified Water Tanks, (Incl. Liner)	\$0	Exempt	Included	\$77,360	\$31,950	W/Field Labor	\$109,310	1	\$109,310	1993			
1300	1.2B.02 435	Clarified Water Tank Agitator	\$20,358	Exempt	Included	\$0	\$2,000	W/Field Labor	\$22,358	1	\$22,358	1994			
1300	1.2B.02 435	Clarified Water Pumps	\$10,533	Exempt	Included	\$0	\$2,500	W/Field Labor	\$13,033	2	\$26,066	1994			

APPENDIX B  
MAJOR EQUIPMENT COSTS  
AREA NO. 1300: BYPRODUCT PROCESSING & HANDLING SYSTEM

Area No.	Item No.	Item Name	Cost/Unit							No. of Units	Total Cost	Year
			F. O. B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total			
1300	1.2B.06 270	Gypsum Handling Equipment, Including Belt Conveyors	\$384,174	Exempt	Included	\$0	\$265,616	W/Field Labor	\$649,790	1	\$649,790	1994
1300	1.2B.06	Balance of Job - Mechanical	\$0	Exempt	Included	\$372,678	\$187,067	W/Field Labor	\$559,745	1	\$559,745	1994
1300	1.2B.06	Balance of Job - Electrical/I&C	\$0	Exempt	Included	\$1,070	\$266,552	W/Field Labor	\$267,622	1	\$267,622	1994
1300	1.2B.06	Balance of Job - Civil (Incl. Gypsum Storage Bldg)	\$0	Exempt	Included	\$447,281	\$291,302	W/Field Labor	\$738,583	1	\$738,583	1994

A. Subtotal Installed Cost \$4,243,000  
 B. Retrofit Costs Included  
 C. Process Contingency Included  
 D. Total Installed Equipment Cost \$4,243,000

**APPENDIX B  
MAJOR EQUIPMENT COSTS  
AREA NO. 1400: WASTE HANDLING SYSTEM**

Area No.	Item No.	Item Name	Cost/Unit							No. of Units	Total Cost	Year
			F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total			
1400	1.2B.02 435	Blowdown Pumps	\$7,467	Exempt	Included	\$0	\$1,000	W/Field Labor	\$8,467	2	\$16,934	1994
1400	1.2B.05 441	FGD Blowdown Equipment (Complete)	\$1,602,131	Exempt	Included	\$0	\$0	W/Field Labor	\$1,602,131	1	\$1,602,131	1994
1400	1.2B.05 441	Equalization Tank (Incl. Insulation)	W/FGD Equipment	Exempt	Included	\$0	\$24,000	W/Field Labor	\$24,000	1	\$24,000	1994
1400	1.2B.05 441	Desaturation Tank	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Heavy Metal Tank	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Coagulation Tank	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Ferric Chloride Tank	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Organo Sulfide Tank	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Lime Slurry Tank	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Sludge Holding Tank	W/FGD Equipment	Exempt	Included	\$0	\$90,627	W/Field Labor	\$90,627	1	\$90,627	1994
1400	1.2B.05 441	CPR Sludge Holding Tank	W/FGD Equipment	Exempt	Included	\$0	\$68,500	W/Field Labor	\$68,500	1	\$68,500	1994
1400	1.2B.05 441	FGD Filtrate Tank330	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	CPR Filtrate Tank	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Equalization Tank Agitator	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	pH Elevation/Saturation Tank Agitator	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Heavy Metal Precip. Tank Agitator	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Coagulation Tank Agitator	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Densadeg Reactor Agitator	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Lime Slurry Tank Agitator	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05 441	Sludge Holding Tank Agitator	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994
1400	1.2B.05	Ferric Chloride Feed Pumps	W/FGD Equipment	Exempt	Included	\$0	W/Skld	W/Field Labor	\$0	2	\$0	1994

**APPENDIX B  
MAJOR EQUIPMENT COSTS  
AREA NO.1400: WASTE HANDLING SYSTEM**

Area No.	Item No.	Item Name	F.O.B. Equipment	Sales Tax	Freight	Cost/Unit			Indirect Field Labor	Total	No. of Units	Total Cost	Year
						Field Material	Field Labor	Labor					
	441		Equipment										
1400	1.2B.05 441	Organosulfide Feed Pumps	W/FGD Equipment	Exempt	Included	\$0	W/Skid	W/Field Labor	\$0	2	\$0	1994	
1400	1.2B.05 441	Forward Feed Pumps	W/FGD Equipment	Exempt	Included	\$0	\$1,000	W/Field Labor	\$1,000	2	\$2,000	1994	
1400	1.2B.05 441	Sludge Waste Pumps	W/FGD Equipment	Exempt	Included	\$0	\$1,000	W/Field Labor	\$1,000	2	\$2,000	1994	
1400	1.2B.05 441	Sludge Recycle Pumps	W/FGD Equipment	Exempt	Included	\$0	\$1,000	W/Field Labor	\$1,000	2	\$2,000	1994	
1400	1.2B.05 441	Filter Press Feed Pump	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994	
1400	1.2B.05 441	Lime Slurry Pump Skid	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994	
1400	1.2B.05 441	FGD Filtrate Pump	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994	
1400	1.2B.05 441	CPR Filtrate Pump	W/FGD Equipment	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1994	
1400	1.2B.05 441	Densadeg Reactor, (Including Insulation & Liner)	W/FGD Equipment	Exempt	Included	\$0	\$16,282	W/Field Labor	\$16,282	1	\$16,282	1994	
1400	1.2B.05 441	Densadeg Thickener (Including Insulation)	W/FGD Equipment	Exempt	Included	\$0	\$101,453	W/Field Labor	\$101,453	1	\$101,453	1994	
1400	1.2B.05 441	Densadeg Scraper	W/FGD Equipment	Exempt	Included	\$0	\$4,000	W/Field Labor	\$4,000	1	\$4,000	1994	
1400	1.2B.05 443	Product Tank Agitator	W/Brine Concentrator	Exempt	Included	\$0	\$2,000	W/Field Labor	\$2,000	1	\$2,000	1993	
1400	1.2B.05 443	Vapor Compressor W/Sound Enclosure	W/Brine Concentrator	Exempt	Included	\$0	\$20,000	W/Field Labor	\$20,000	1	\$20,000	1993	
1400	1.2B.05	Balance of Job - Mechanical/Piping	\$0	Exempt	Included	\$22,259	\$289,614	W/Field Labor	\$311,873	1	\$311,873	1995	
1400	1.2B.05	Balance of Job - Electrical/I&C	\$0	Exempt	Included	\$	\$37,509	W/Field Labor	\$37,509	1	\$40,509	1995	
1400	1.2B.05	Balance of Job - Civil/Concrete	\$0	Exempt	Included	\$10,000	\$10,400	W/Field Labor	\$20,400	1	\$20,400	1995	

A. Subtotal Installed Cost \$2,363,000  
 B. Retrofit Costs Included  
 C. Process Contingency Included  
 D. Total Installed Equipment Cost \$2,363,000



**APPENDIX B  
MAJOR EQUIPMENT COSTS  
AREA NO. 1500: COMMON SUPPORT SYSTEMS**

Area No.	Item No.	Item Name	Cost/Unit							No. of Units	Total Cost	Year
			F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total			
1500	1.2B.02	Balance of Job - Mechanical	\$0	Included	Included	\$2,634,267	\$2,099,496	W/Field Labor	\$4,733,763	1	\$4,733,763	1994
1500	1.2B.02	Balance of Job - Electrical & I&C	\$0	Exempt	Included	\$4,062,329	\$1,537,283	W/Field Labor	\$5,599,612	1	\$5,599,612	1994
1500	1.2B.02	FGD Building & Site Work	\$0	Exempt	Included	\$9,223,330	\$4,193,096	W/Field Labor	\$13,416,426	1	\$13,416,426	1994

A. Subtotal Installed Cost \$23,750,000  
 B. Retrofit Costs Included  
 C. Process Contingency Included  
 D. Total Installed Equipment Cost \$23,750,000



**APPENDIX C**  
**TECHNOLOGY COST TABLES**

### Limestone Forced-Oxidation/Throwaway Gypsum

**CAPITAL COSTS (market base)**

Plant Size (Mw)	300.0
Capacity Factor	65.0%

	<u>FGD System Titles</u>	<u>\$x1,000,000</u>	<u>\$/kW</u>
	100 Raw Material Receiving and Handling System	5.0	16.8
	200 Fuel Preparation and Storage System	0.0	0.0
	300 Fuel and Oxidant Feed Handling System	0.0	0.0
	400 Combustion / Steam Generation System	0.0	0.0
	500 Combustion Modification Equipment	0.0	0.0
	600 Fuel Gas Processing and Handling System	0.0	0.0
	700 Power Generating System	0.0	0.0
	800 SO <sub>2</sub> Removal System	8.4	28.0
	900 NO <sub>x</sub> Removal System	0.0	0.0
	1000 Particulate Removal System	0.0	0.0
	1100 Flue Gas Handling System	5.2	17.2
	1200 Raw Material Regeneration System	0.0	0.0
	1300 By-Product Processing and Handling System	0.0	0.0
	1400 Waste Handling System	2.2	7.4
	1500 Common Support Systems	11.6	38.7
	1600 Other Systems	6.4	21.4
A	Total Process Capital	38.9	129.6
B	General Facilities		
C	Engineering & Home Office Fees (10% of TPC)	3.9	13.0
D	Project Contingency (10% of A+B+C)	4.3	14.3
E	Total Plant Cost (A+B+C+D)	47.0	156.8
F	Allowance for Funds During Construction	0.9	3.0
G	Total Plant Investment	47.9	159.8
H	Royalty Allowance	NA	NA
I	Preproduction Costs	2.9	9.7
J	Inventory Capital	0.737	2.46
K	Initial Catalyst & Chemicals	NA	NA
L	Subtotal Capital (G+H+I+J+K)	52	171.9
M	Cost of Construction Downtime	21	70
N	Total Capital Requirement	73	242.1

### Limestone Forced-Oxidation/Throwaway Gypsum

<u>Fixed O &amp; M Costs</u>	<u>Units</u>	<u>Quantity</u>	<u>\$ / Unit</u>	<u>\$(xM)/Yr</u>
Operating Labor	Mnhr/hr	27,040	23.00	0.62
Maintenance Labor				0.19
Maintenance Material				0.28
Administration / Support Labor				0.24
Subtotal Fixed Costs				1.34
<u>Variable Operating Costs</u>				
Fuels				
n/a	Ton			
Sorbent				
Limestone	Ton	71,118	15.00	1.07
Chemicals/Catalyst				
Formic Acid	Lbs	0	0.43	0.00
Utilities				
Electric Power	kW x10 <sup>3</sup>	45	0.050	2.27
By-products Credits				
Gypsum	Ton	0	3.00	0.00
Calcium Chloride	Ton		1.00	
Flyash	Ton	0	5.33	0.00
Waste Disposal Charges				
Lime	Ton	0	80.82	0.00
Sludge Removal	Ton	114,563	10.00	1.15
Subtotal Variable Cost				4.48
Total O & M Cost (Fixed + Variable)				5.82

### Limestone Forced-Oxidation/Throwaway Gypsum

<u>Power Plant Attributes</u>		<u>Units</u>	<u>Value</u>		
Plant Capacity (net)		Mwe	300		
Power Produced (net)		10 <sup>9</sup> kWh/yr	1.708		
Capacity Factor		%	65.0%		
Plant Life		yr	15		
Coal Feed		10 <sup>6</sup> tons/yr	0.629		
Sulfur in Coal		wt %	3.2%		
Emissions Control Data	Units	SO2	NOx	TSP	PM10
Removal Efficiency	%	95.0%			
Emissions Standard	lb/10 <sup>6</sup> BTU	1.20			
Emissions Without Controls	lb/10 <sup>6</sup> BTU	5.01			
Emissions With Controls	lb/10 <sup>6</sup> BTU	0.25			
Amount Removed	Tons / Year	38,268			
		Current Dollars		Constant Dollars	
Levelized Cost of Power	Factor	Mills/kWh	Factor	Mills/kWh	
Capital Charge	0.1604	6.82	0.124	5.27	
Fixed O & M Cost	1.293	1.01	1.000	0.78	
Variable Operating Cost	1.293	3.39	1.000	2.63	
Total Cost		11.23		8.68	
Levelized Cost - SO2 Basis	Factor	\$/ton Removed	Factor	\$/ton Removed	
Capital Charge	0.1604	304.47	0.124	235.37	
Fixed O & M Cost	1.293	45.12	1.000	34.89	
Variable Operating Cost	1.293	151.52	1.000	117.18	
Total Cost		501.10		387.45	
Levelized Cost - SO2 + NOx Basis	Factor	\$/ton Removed	Factor	\$/ton Removed	
Capital Charge	0.1604	0.00	0.124	0.00	
Fixed O & M Cost	1.293	0.00	1.000	0.00	
Variable Operating Cost	1.293	0.00	1.000	0.00	
Total Cost		0.00		0.00	

### Limestone Forced-Oxidation/Wallboard Gypsum

CAPITAL COSTS (market base)	
Plant Size (Mw)	300.0
Capacity Factor	65.0%

	<u>FGD System Titles</u>	<u>\$x1,000,000</u>	<u>\$/kW</u>
	100 Raw Material Receiving and Handling System	5.3	17.7
	200 Fuel Preparation and Storage System	0.0	0.0
	300 Fuel and Oxidant Feed Handling System	0.0	0.0
	400 Combustion / Steam Generation System	0.0	0.0
	500 Combustion Modification Equipment	0.0	0.0
	600 Fuel Gas Processing and Handling System	0.0	0.0
	700 Power Generating System	0.0	0.0
	800 SO <sub>2</sub> Removal System	9.2	30.7
	900 NO <sub>x</sub> Removal System	0.0	0.0
	1000 Particulate Removal System	0.0	0.0
	1100 Flue Gas Handling System	5.6	18.5
	1200 Raw Material Regeneration System	0.0	0.0
	1300 By-Product Processing and Handling System	6.1	20.4
	1400 Waste Handling System	0.0	0.0
	1500 Common Support Systems	12.8	42.7
	1600 Other Systems	6.8	22.6
A	Total Process Capital	45.8	152.7
B	General Facilities		
C	Engineering & Home Office Fees (10% of TPC)	4.6	15.3
D	Project Contingency (10% of A+B+C)	5.0	16.8
E	Total Plant Cost (A+B+C+D)	55.4	184.7
F	Allowance for Funds During Construction	1.1	3.5
G	Total Plant Investment	56.5	188.2
H	Royalty Allowance	NA	NA
I	Preproduction Costs	2.1	7.1
J	Inventory Capital	0.485	1.62
K	Initial Catalyst & Chemicals	NA	NA
L	Subtotal Capital (G+H+I+J+K)	59	197.0
M	Cost of Construction Downtime	21	70
N	Total Capital Requirement	80	267.2

### Limestone Forced-Oxidation/Wallboard Gypsum

<u>Fixed O &amp; M Costs</u>	<u>Units</u>	<u>Quantity</u>	<u>\$ / Unit</u>	<u>\$(xM)/Yr</u>
Operating Labor	Mnhr/hr	27,040	23.00	0.62
Maintenance Labor				0.18
Maintenance Material				0.28
Administration / Support Labor				0.24
Subtotal Fixed Costs				1.33
<u>Variable Operating Costs</u>				
Fuels				
n/a	Ton			
Sorbent				
Limestone	Ton	67,929	15.00	1.02
Chemicals/Catalyst				
Formic Acid	Lbs	171,845	0.43	0.07
Utilities				
Electric Power	kW x10 <sup>3</sup>	46	0.050	2.30
By-products Credits				
Gypsum	Ton	123,674	3.00	(0.37)
Calcium Chloride	Ton		1.00	
Flyash	Ton	0	5.33	0.00
Waste Disposal Charges				
Lime	Ton	0	80.82	0.00
Sludge Removal	Ton	0	10.00	0.00
Subtotal Variable Cost				3.02
Total O & M Cost (Fixed + Variable)				4.35



### Limestone Forced-Oxidation/Wallboard Gypsum

<u>Power Plant Attributes</u>		<u>Units</u>	<u>Value</u>		
Plant Capacity (net)		Mwe	300		
Power Produced (net)		10 <sup>9</sup> kWh/yr	1.708		
Capacity Factor		%	65.0%		
Plant Life		yr	15		
Coal Feed		10 <sup>6</sup> tons/yr	0.629		
Sulfur in Coal		wt %	3.2%		
<b>Emissions Control Data</b>	<b>Units</b>	<b>SO2</b>	<b>NOx</b>	<b>TSP</b>	<b>PM10</b>
Removal Efficiency	%	95.0%			
Emissions Standard	lb/10 <sup>6</sup> BTU	1.20			
Emissions Without Controls	lb/10 <sup>6</sup> BTU	5.01			
Emissions With Controls	lb/10 <sup>6</sup> BTU	0.25			
Amount Removed	Tons / Year	38,268			
		<b>Current Dollars</b>		<b>Constant Dollars</b>	
Levelized Cost of Power		Factor	Mills/kWh	Factor	Mills/kWh
Capital Charge		0.1604	7.53	0.124	5.82
Fixed O & M Cost		1.293	1.00	1.000	0.78
Variable Operating Cost		1.293	2.29	1.000	1.77
Total Cost			10.82		8.37
<b>Levelized Cost - SO2 Basis</b>		<b>Factor</b>	<b>\$/ton Removed</b>	<b>Factor</b>	<b>\$/ton Removed</b>
Capital Charge		0.1604	336.14	0.124	259.86
Fixed O & M Cost		1.293	44.80	1.000	34.65
Variable Operating Cost		1.293	102.11	1.000	78.97
Total Cost			483.06		373.48
<b>Levelized Cost - SO2 + NOx Basis</b>		<b>Factor</b>	<b>\$/ton Removed</b>	<b>Factor</b>	<b>\$/ton Removed</b>
Capital Charge		0.1604	0.00	0.124	0.00
Fixed O & M Cost		1.293	0.00	1.000	0.00
Variable Operating Cost		1.293	0.00	1.000	0.00
Total Cost			0.00		0.00

### Magnesium Enhanced Lime

CAPITAL COSTS (market base)			
	Plant Size (Mw)	300.0	
	Capacity Factor	65.0%	
	<u>FGD System Titles</u>	<u>\$x1,000,000</u>	<u>\$/kW</u>
	100 Raw Material Receiving and Handling System	3.7	12.2
	200 Fuel Preparation and Storage System	0.0	0.0
	300 Fuel and Oxidant Feed Handling System	0.0	0.0
	400 Combustion / Steam Generation System	0.0	0.0
	500 Combustion Modification Equipment	0.0	0.0
	600 Fuel Gas Processing and Handling System	0.0	0.0
	700 Power Generating System	0.0	0.0
	800 SO <sub>2</sub> Removal System	8.1	27.0
	900 NO <sub>x</sub> Removal System	0.0	0.0
	1000 Particulate Removal System	0.0	0.0
	1100 Flue Gas Handling System	5.5	18.5
	1200 Raw Material Regeneration System	0.0	0.0
	1300 By-Product Processing and Handling System	0.0	0.0
	1400 Waste Handling System	3.4	11.3
	1500 Common Support Systems	11.7	39.2
	1600 Other Systems	6.8	22.6
A	Total Process Capital	39.3	130.8
B	General Facilities		
C	Engineering & Home Office Fees (10% of TPC)	3.9	13.1
D	Project Contingency (10% of A+B+C)	4.3	14.4
E	Total Plant Cost (A+B+C+D)	47.5	158.3
F	Allowance for Funds During Construction	0.9	3.0
G	Total Plant Investment	48.4	161.3
H	Royalty Allowance	NA	NA
I	Preproduction Costs	3.6	11.9
J	Inventory Capital	0.956	3.19
K	Initial Catalyst & Chemicals	NA	NA
L	Subtotal Capital (G+H+I+J+K)	53	176.4
M	Cost of Construction Downtime	21	70
N	Total Capital Requirement	74	246.6

### Magnesium Enhanced Lime

<u>Fixed O &amp; M Costs</u>	<u>Units</u>	<u>Quantity</u>	<u>\$ / Unit</u>	<u>\$(xM)/Yr</u>
Operating Labor	Mnhr/hr	27,040	23.00	0.62
Maintenance Labor				0.19
Maintenance Material				0.28
Administration / Support Labor				0.24
<b>Subtotal Fixed Costs</b>				<b>1.34</b>
<u>Variable Operating Costs</u>				
Fuels				
n/a	Ton			
Sorbent				
Ga - Lime	Ton	41,282	55.00	2.27
Chemicals/Catalyst				
Formic Acid	Lbs	0	0.43	0.00
Utilities				
Electric Power	kW x10 <sup>3</sup>	38	0.050	1.92
By-products Credits				
Gypsum	Ton	0	3.00	0.00
Calcium Chloride	Ton		1.00	
Flyash	Ton	0	5.33	0.00
Waste Disposal Charges				
Lime	Ton	2,317	55.00	0.13
Sludge Removal	Ton	149,524	10.00	1.50
<b>Subtotal Variable Cost</b>				<b>5.81</b>
<b>Total O &amp; M Cost (Fixed + Variable)</b>				<b>7.15</b>

### Magnesium Enhanced Lime

<u>Power Plant Attributes</u>		<u>Units</u>	<u>Value</u>		
Plant Capacity (net)		Mwe	300		
Power Produced (net)		10 <sup>9</sup> kWh/yr	1.708		
Capacity Factor		%	65.0%		
Plant Life		yr	15		
Coal Feed		10 <sup>6</sup> tons/yr	0.629		
Sulfur in Coal		wt %	3.2%		
Emissions Control Data	Units	SO2	NOx	TSP	PM10
Removal Efficiency	%	95.0%			
Emissions Standard	lb/10 <sup>6</sup> BTU	1.20			
Emissions Without Controls	lb/10 <sup>6</sup> BTU	5.01			
Emissions With Controls	lb/10 <sup>6</sup> BTU	0.25			
Amount Removed	Tons / Year	38,268			
		Current Dollars		Constant Dollars	
Levelized Cost of Power		Factor	Mills/kWh	Factor	Mills/kWh
Capital Charge		0.1604	6.95	0.124	5.37
Fixed O & M Cost		1.293	1.01	1.000	0.78
Variable Operating Cost		1.293	4.40	1.000	3.40
Total Cost			12.36		9.56
Levelized Cost - SO2 Basis		Factor	\$/ton Removed	Factor	\$/ton Removed
Capital Charge		0.1604	310.14	0.124	239.76
Fixed O & M Cost		1.293	45.29	1.000	35.03
Variable Operating Cost		1.293	196.43	1.000	151.92
Total Cost			551.86		426.71
Levelized Cost - SO2 + NOx Basis		Factor	\$/ton Removed	Factor	\$/ton Removed
Capital Charge		0.1604	0.00	0.124	0.00
Fixed O & M Cost		1.293	0.00	1.000	0.00
Variable Operating Cost		1.293	0.00	1.000	0.00
Total Cost			0.00		0.00

### Thiosulfate/Inhibited Oxidation Limestone

**CAPITAL COSTS (market base)**

Plant Size (Mw)	300.0
Capacity Factor	65.0%

	<u>FGD System Titles</u>	<u>\$x1,000,000</u>	<u>\$/kW</u>
	100 Raw Material Receiving and Handling System	6.0	19.9
	200 Fuel Preparation and Storage System	0.0	0.0
	300 Fuel and Oxidant Feed Handling System	0.0	0.0
	400 Combustion / Steam Generation System	0.0	0.0
	500 Combustion Modification Equipment	0.0	0.0
	600 Fuel Gas Processing and Handling System	0.0	0.0
	700 Power Generating System	0.0	0.0
	800 SO <sub>2</sub> Removal System	8.4	27.9
	900 NO <sub>x</sub> Removal System	0.0	0.0
	1000 Particulate Removal System	0.0	0.0
	1100 Flue Gas Handling System	5.5	18.5
	1200 Raw Material Regeneration System	0.0	0.0
	1300 By-Product Processing and Handling System	0.0	0.0
	1400 Waste Handling System	2.5	8.5
	1500 Common Support Systems	12.3	40.9
	1600 Other Systems	7.8	26.0
A	Total Process Capital	42.5	141.6
B	General Facilities		
C	Engineering & Home Office Fees (10% of TPC)	4.2	14.2
D	Project Contingency (10% of A+B+C)	4.7	15.6
E	Total Plant Cost (A+B+C+D)	51.4	171.3
F	Allowance for Funds During Construction	1.0	3.3
G	Total Plant Investment	52.4	174.6
H	Royalty Allowance	NA	NA
I	Preproduction Costs	3.1	10.3
J	Inventory Capital	0.784	2.61
K	Initial Catalyst & Chemicals	NA	NA
L	Subtotal Capital (G+H+I+J+K)	56	187.4
M	Cost of Construction Downtime	21	70
N	Total Capital Requirement	77	257.6

**Thiosulfate/Inhibited Oxidation Limestone**

<u>Fixed O &amp; M Costs</u>	<u>Units</u>	<u>Quantity</u>	<u>\$ / Unit</u>	<u>\$(xM)/Yr</u>
Operating Labor	Mnhr/hr	27,040	23.00	0.62
Maintenance Labor				0.21
Maintenance Material				0.31
Administration / Support Labor				0.25
Subtotal Fixed Costs				1.38
 <u>Variable Operating Costs</u>				
Fuels				
n/a	Ton			
Sorbent				
Limestone	Ton	71,118	15.00	1.07
Chemicals/Catalyst				
Sulfur Emulsion	Ton	36	220.00	0.008
Utilities				
Electric Power	kW x10 <sup>3</sup>	39	0.050	1.93
By-products Credits				
Gypsum	Ton	0	3.00	0.00
Calcium Chloride	Ton		1.00	
Flyash	Ton	0	5.33	0.00
Waste Disposal Charges				
Lime	Ton	4,436	55.00	0.24
Sludge Removal	Ton	152,315	10.00	1.52
Subtotal Variable Cost				4.77
Total O & M Cost (Fixed + Variable)				6.16

### Thiosulfate/Inhibited Oxidation Limestone

<u>Power Plant Attributes</u>		<u>Units</u>	<u>Value</u>		
Plant Capacity (net)		Mwe	300		
Power Produced (net)		10 <sup>9</sup> kWh/yr	1.708		
Capacity Factor		%	65.0%		
Plant Life		yr	15		
Coal Feed		10 <sup>6</sup> tons/yr	0.629		
Sulfur in Coal		wt %	3.2%		
Emissions Control Data	Units	SO2	NOx	TSP	PM10
Removal Efficiency	%	95.0%			
Emissions Standard	lb/10 <sup>6</sup> BTU	1.20			
Emissions Without Controls	lb/10 <sup>6</sup> BTU	5.01			
Emissions With Controls	lb/10 <sup>6</sup> BTU	0.25			
Amount Removed	Tons / Year	38,268			
		Current Dollars		Constant Dollars	
Levelized Cost of Power		Factor	Mills/kWh	Factor	Mills/kWh
Capital Charge		0.1604	7.26	0.124	5.61
Fixed O & M Cost		1.293	1.05	1.000	0.81
Variable Operating Cost		1.293	3.61	1.000	2.79
Total Cost			11.92		9.21
Levelized Cost - SO2 Basis		Factor	\$/ton Removed	Factor	\$/ton Removed
Capital Charge		0.1604	323.98	0.124	250.46
Fixed O & M Cost		1.293	46.77	1.000	36.17
Variable Operating Cost		1.293	161.24	1.000	124.70
Total Cost			531.98		411.33
Levelized Cost - SO2 + NOx Basis		Factor	\$/ton Removed	Factor	\$/ton Removed
Capital Charge		0.1604	0.00	0.124	0.00
Fixed O & M Cost		1.293	0.00	1.000	0.00
Variable Operating Cost		1.293	0.00	1.000	0.00
Total Cost			0.00		0.00

### DBA Enhanced Limestone

CAPITAL COSTS (market base)	
Plant Size (Mw)	300.0
Capacity Factor	65.0%

	<u>FGD System Titles</u>	<u>\$x1,000,000</u>	<u>\$/kW</u>
	100 Raw Material Receiving and Handling System	5.1	16.9
	200 Fuel Preparation and Storage System	0.0	0.0
	300 Fuel and Oxidant Feed Handling System	0.0	0.0
	400 Combustion / Steam Generation System	0.0	0.0
	500 Combustion Modification Equipment	0.0	0.0
	600 Fuel Gas Processing and Handling System	0.0	0.0
	700 Power Generating System	0.0	0.0
	800 SO <sub>2</sub> Removal System	8.3	27.6
	900 NO <sub>x</sub> Removal System	0.0	0.0
	1000 Particulate Removal System	0.0	0.0
	1100 Flue Gas Handling System	5.0	16.7
	1200 Raw Material Regeneration System	0.0	0.0
	1300 By-Product Processing and Handling System	0.0	0.0
	1400 Waste Handling System	2.2	7.4
	1500 Common Support Systems	11.6	38.5
	1600 Other Systems	6.4	21.4
A	Total Process Capital	38.5	128.5
B	General Facilities		
C	Engineering & Home Office Fees (10% of TPC)	3.9	12.8
D	Project Contingency (10% of A+B+C)	4.2	14.1
E	Total Plant Cost (A+B+C+D)	46.6	155.5
F	Allowance for Funds During Construction	0.9	3.0
G	Total Plant Investment	47.5	158.4
H	Royalty Allowance	NA	NA
I	Preproduction Costs	3.0	9.9
J	Inventory Capital	0.758	2.53
K	Initial Catalyst & Chemicals	NA	NA
L	Subtotal Capital (G+H+I+J+K)	51	170.9
M	Cost of Construction Downtime	21	70
N	Total Capital Requirement	72	241.1



### DBA Enhanced Limestone

<u>Fixed O &amp; M Costs</u>	<u>Units</u>	<u>Quantity</u>	<u>\$ / Unit</u>	<u>\$(xM)/Yr</u>
Operating Labor	Mnhr/hr	27,040	23.00	0.62
Maintenance Labor				0.19
Maintenance Material				0.28
Administration / Support Labor				0.24
Subtotal Fixed Costs				1.33
<u>Variable Operating Costs</u>				
Fuels				
n/a	Ton			
Sorbent				
Limestone	Ton	71,118	15.00	1.07
Chemicals/Catalyst				
Dibasic Acid	Ton	386	360.00	0.139
Utilities				
Electric Power	kW x10 <sup>3</sup>	45	0.050	2.26
By-products Credits				
Gypsum	Ton	0	3.00	0.00
Calcium Chloride	Ton		1.00	
Flyash	Ton	0	5.33	0.00
Waste Disposal Charges				
Lime	Ton	0	55.00	0.00
Sludge Removal	Ton	114,563	10.00	1.15
Subtotal Variable Cost				4.61
Total O & M Cost (Fixed + Variable)				5.94

### DBA Enhanced Limestone

<u>Power Plant Attributes</u>		<u>Units</u>	<u>Value</u>		
Plant Capacity (net)		Mwe	300		
Power Produced (net)		10 <sup>9</sup> kWh/yr	1.708		
Capacity Factor		%	65.0%		
Plant Life		yr	15		
Coal Feed		10 <sup>6</sup> tons/yr	0.629		
Sulfur in Coal		wt %	3.2%		
Emissions Control Data	Units	SO2	NOx	TSP	PM10
Removal Efficiency	%	95.0%			
Emissions Standard	lb/10 <sup>6</sup> BTU	1.20			
Emissions Without Controls	lb/10 <sup>6</sup> BTU	5.01			
Emissions With Controls	lb/10 <sup>6</sup> BTU	0.25			
Amount Removed	Tons / Year	38,268			
		Current Dollars		Constant Dollars	
Levelized Cost of Power		Factor	Mills/kWh	Factor	Mills/kWh
Capital Charge		0.1604	6.79	0.124	5.25
Fixed O & M Cost		1.293	1.01	1.000	0.78
Variable Operating Cost		1.293	3.49	1.000	2.70
Total Cost			11.29		8.73
Levelized Cost - SO2 Basis		Factor	\$/ton Removed	Factor	\$/ton Removed
Capital Charge		0.1604	303.12	0.124	234.33
Fixed O & M Cost		1.293	44.97	1.000	34.78
Variable Operating Cost		1.293	155.73	1.000	120.44
Total Cost			503.81		389.55
Levelized Cost - SO2 + NOx Basis		Factor	\$/ton Removed	Factor	\$/ton Removed
Capital Charge		0.1604	0.00	0.124	0.00
Fixed O & M Cost		1.293	0.00	1.000	0.00
Variable Operating Cost		1.293	0.00	1.000	0.00
Total Cost			0.00		0.00

### Pure Air - Cocurrent Scrubber

CAPITAL COSTS (market base)	
Plant Size (Mw)	300.0
Capacity Factor	65.0%

	<u>FGD System Titles</u>	<u>\$x1,000,000</u>	<u>\$/kW</u>
	100 Raw Material Receiving and Handling System	5.7	18.9
	200 Fuel Preparation and Storage System	0.0	0.0
	300 Fuel and Oxidant Feed Handling System	0.0	0.0
	400 Combustion / Steam Generation System	0.0	0.0
	500 Combustion Modification Equipment	0.0	0.0
	600 Fuel Gas Processing and Handling System	0.0	0.0
	700 Power Generating System	0.0	0.0
	800 SO <sub>2</sub> Removal System	7.6	25.2
	900 NO <sub>x</sub> Removal System	0.0	0.0
	1000 Particulate Removal System	0.0	0.0
	1100 Flue Gas Handling System	5.5	18.5
	1200 Raw Material Regeneration System	0.0	0.0
	1300 By-Product Processing and Handling System	0.0	0.0
	1400 Waste Handling System	1.6	5.3
	1500 Common Support Systems	11.6	38.8
	1600 Other Systems	6.8	22.6
A	Total Process Capital	38.8	129.4
B	General Facilities		
C	Engineering & Home Office Fees (10% of TPC)	3.9	12.9
D	Project Contingency (10% of A+B+C)	4.3	14.2
E	Total Plant Cost (A+B+C+D)	47.0	156.5
F	Allowance for Funds During Construction	0.9	3.0
G	Total Plant Investment	47.9	159.5
H	Royalty Allowance	NA	NA
I	Preproduction Costs	2.5	8.3
J	Inventory Capital	0.597	1.99
K	Initial Catalyst & Chemicals	NA	NA
L	Subtotal Capital (G+H+I+J+K)	51	169.8
M	Cost of Construction Downtime	21	70
N	Total Capital Requirement	72	240.0

**Pure Air - Cocurrent Scrubber**

<u>Fixed O &amp; M Costs</u>	<u>Units</u>	<u>Quantity</u>	<u>\$ / Unit</u>	<u>\$(xM)/Yr</u>
Operating Labor	Mnhr/hr	27,040	23.00	0.62
Maintenance Labor				0.19
Maintenance Material				0.28
Administration / Support Labor				0.24
Subtotal Fixed Costs				1.33
 <u>Variable Operating Costs</u>				
Fuels				
n/a	Ton			
Sorbent				
Limestone	Ton	67,929	15.00	1.02
Chemicals/Catalyst				
Formic Acid	Lbs	0	0.43	0.00
Utilities				
Electric Power	kW x10 <sup>3</sup>	30	0.050	1.50
By-products Credits				
Gypsum	Ton	0	3.00	0.00
Calcium Chloride	Ton		1.00	
Flyash	Ton	0	5.33	0.00
Waste Disposal Charges				
Lime	Ton	0	80.82	0.00
Sludge Removal	Ton	111,318	10.00	1.11
Subtotal Variable Cost				3.63
Total O & M Cost (Fixed + Variable)				4.97

**Pure Air - Cocurrent Scrubber**

<u>Power Plant Attributes</u>		<u>Units</u>	<u>Value</u>		
Plant Capacity (net)		Mwe	300		
Power Produced (net)		10 <sup>9</sup> kWh/yr	1.708		
Capacity Factor		%	65.0%		
Plant Life		yr	15		
Coal Feed		10 <sup>6</sup> tons/yr	0.629		
Sulfur in Coal		wt %	3.2%		
Emissions Control Data	Units	SO2	NOx	TSP	PM10
Removal Efficiency	%	95.0%			
Emissions Standard	lb/10 <sup>6</sup> BTU	1.20			
Emissions Without Controls	lb/10 <sup>6</sup> BTU	5.01			
Emissions With Controls	lb/10 <sup>6</sup> BTU	0.25			
Amount Removed	Tons / Year	38,268			
		<u>Current Dollars</u>		<u>Constant Dollars</u>	
Levelized Cost of Power		Factor	Mills/kWh	Factor	Mills/kWh
Capital Charge		0.1604	6.76	0.124	5.23
Fixed O & M Cost		1.293	1.01	1.000	0.78
Variable Operating Cost		1.293	2.75	1.000	2.13
Total Cost			10.52		8.14
Levelized Cost - SO2 Basis		Factor	\$/ton Removed	Factor	\$/ton Removed
Capital Charge		0.1604	301.78	0.124	233.30
Fixed O & M Cost		1.293	45.09	1.000	34.87
Variable Operating Cost		1.293	122.79	1.000	94.97
Total Cost			469.66		363.13
Levelized Cost - SO2 + NOx Basis		Factor	\$/ton Removed	Factor	\$/ton Removed
Capital Charge		0.1604	0.00	0.124	0.00
Fixed O & M Cost		1.293	0.00	1.000	0.00
Variable Operating Cost		1.293	0.00	1.000	0.00
Total Cost			0.00		0.00

### Chiyoda Thoroughbred (CT 121)

<b>CAPITAL COSTS (market base)</b>	
Plant Size (Mw)	300.0
Capacity Factor	65.0%

<u>FGD System Titles</u>	<u>\$x1,000,000</u>	<u>\$/kW</u>
100 Raw Material Receiving and Handling System	5.3	17.6
200 Fuel Preparation and Storage System	0.0	0.0
300 Fuel and Oxidant Feed Handling System	0.0	0.0
400 Combustion / Steam Generation System	0.0	0.0
500 Combustion Modification Equipment	0.0	0.0
600 Fuel Gas Processing and Handling System	0.0	0.0
700 Power Generating System	0.0	0.0
800 SO <sub>2</sub> Removal System	5.9	19.7
900 NO <sub>x</sub> Removal System	0.0	0.0
1000 Particulate Removal System	0.0	0.0
1100 Flue Gas Handling System	5.6	18.6
1200 Raw Material Regeneration System	0.0	0.0
1300 By-Product Processing and Handling System	0.0	0.0
1400 Waste Handling System	1.7	5.8
1500 Common Support Systems	11.1	37.1
1600 Other Systems	6.8	22.6
A Total Process Capital	36.4	121.4
B General Facilities		
C Engineering & Home Office Fees (10% of TPC)	3.6	12.1
D Project Contingency (10% of A+B+C)	4.0	13.4
E Total Plant Cost (A+B+C+D)	44.1	146.9
F Allowance for Funds During Construction	0.8	2.8
G Total Plant Investment	44.9	149.7
H Royalty Allowance	NA	NA
I Preproduction Costs	2.4	7.9
J Inventory Capital	0.565	1.88
K Initial Catalyst & Chemicals	NA	NA
L Subtotal Capital (G+H+I+J+K)	48	159.5
M Cost of Construction Downtime	21	70
N Total Capital Requirement	69	229.7

**Chiyoda Thoroughbred (CT 121)**

<u>Fixed O &amp; M Costs</u>	<u>Units</u>	<u>Quantity</u>	<u>\$ / Unit</u>	<u>\$(xM)/Yr</u>
Operating Labor	Mnhr/hr	27,040	23.00	0.62
Maintenance Labor				0.18
Maintenance Material				0.26
Administration / Support Labor				0.24
<b>Subtotal Fixed Costs</b>				<b>1.30</b>
 <u>Variable Operating Costs</u>				
Fuels				
n/a	Ton			
Sorbent				
Limestone	Ton	65,310	15.00	0.98
Chemicals/Catalyst				
Dibasic Acid	Ton	0	360.00	0.000
Utilities				
Electric Power	kW x10 <sup>3</sup>	27	0.050	1.37
By-products Credits				
Gypsum	Ton	0	3.00	0.00
Calcium Chloride	Ton		1.00	
Flyash	Ton	0	5.33	0.00
Waste Disposal Charges				
Lime	Ton	0	55.00	0.00
Sludge Removal	Ton	108,755	10.00	1.09
 <b>Subtotal Variable Cost</b>				 <b>3.44</b>
 <b>Total O &amp; M Cost (Fixed + Variable)</b>				 <b>4.74</b>

### Chiyoda Thoroughbred (CT 121)

<u>Power Plant Attributes</u>		<u>Units</u>	<u>Value</u>			
Plant Capacity (net)		Mwe	300			
Power Produced (net)		10 <sup>9</sup> kWh/yr	1.708			
Capacity Factor		%	65.0%			
Plant Life		yr	15			
Coal Feed		10 <sup>6</sup> tons/yr	0.629			
Sulfur in Coal		wt %	3.2%			
Emissions Control Data		Units	SO2	NOx	TSP	PM10
Removal Efficiency		%	95.0%			
Emissions Standard		lb/10 <sup>6</sup> BTU	1.20			
Emissions Without Controls		lb/10 <sup>6</sup> BTU	5.01			
Emissions With Controls		lb/10 <sup>6</sup> BTU	0.25			
Amount Removed		Tons / Year	38,268			
		Current Dollars		Constant Dollars		
Levelized Cost of Power		Factor	Mills/kWh	Factor	Mills/kWh	
Capital Charge		0.1604	6.47	0.124	5.00	
Fixed O & M Cost		1.293	0.99	1.000	0.76	
Variable Operating Cost		1.293	2.60	1.000	2.01	
Total Cost			10.06		7.78	
Levelized Cost - SO2 Basis		Factor	\$/ton Removed	Factor	\$/ton Removed	
Capital Charge		0.1604	288.86	0.124	223.31	
Fixed O & M Cost		1.293	44.00	1.000	34.03	
Variable Operating Cost		1.293	116.21	1.000	89.88	
Total Cost			449.08		347.22	
Levelized Cost - SO2 + NOx Basis		Factor	\$/ton Removed	Factor	\$/ton Removed	
Capital Charge		0.1604	0.00	0.124	0.00	
Fixed O & M Cost		1.293	0.00	1.000	0.00	
Variable Operating Cost		1.293	0.00	1.000	0.00	
Total Cost			0.00		0.00	



### Lime Spray Dryer

**CAPITAL COSTS (market base)**

Plant Size (Mw)	300.0
Capacity Factor	65.0%

	<u>FGD System Titles</u>	<u>\$x1,000,000</u>	<u>\$/kW</u>
	100 Raw Material Receiving and Handling System	4.3	14.4
	200 Fuel Preparation and Storage System	0.0	0.0
	300 Fuel and Oxidant Feed Handling System	0.0	0.0
	400 Combustion / Steam Generation System	0.0	0.0
	500 Combustion Modification Equipment	0.0	0.0
	600 Fuel Gas Processing and Handling System	0.0	0.0
	700 Power Generating System	0.0	0.0
	800 SO <sub>2</sub> Removal System	10.5	34.9
	900 NO <sub>x</sub> Removal System	0.0	0.0
	1000 Particulate Removal System	0.0	0.0
	1100 Flue Gas Handling System	6.0	20.1
	1200 Raw Material Regeneration System	0.0	0.0
	1300 By-Product Processing and Handling System	0.0	0.0
	1400 Waste Handling System	1.8	6.0
	1500 Common Support Systems	12.1	40.5
	1600 Other Systems	6.8	22.6
A	Total Process Capital	41.6	138.5
B	General Facilities		
C	Engineering & Home Office Fees (10% of TPC)	4.2	13.9
D	Project Contingency (10% of A+B+C)	4.6	15.2
E	Total Plant Cost (A+B+C+D)	50.3	167.6
F	Allowance for Funds During Construction	1.0	3.2
G	Total Plant Investment	51.2	170.8
H	Royalty Allowance	NA	NA
I	Preproduction Costs	4.1	13.5
J	Inventory Capital	1.107	3.69
K	Initial Catalyst & Chemicals	NA	NA
L	Subtotal Capital (G+H+I+J+K)	56	188.0
M	Cost of Construction Downtime	21	70
N	Total Capital Requirement	77	258.2

**Lime Spray Dryer**

<u>Fixed O &amp; M Costs</u>	<u>Units</u>	<u>Quantity</u>	<u>\$ / Unit</u>	<u>\$(xM)/Yr</u>
Operating Labor	Mnhr/hr	27,040	23.00	0.62
Maintenance Labor				0.20
Maintenance Material				0.30
Administration / Support Labor				0.25
Subtotal Fixed Costs				1.37
<u>Variable Operating Costs</u>				
Fuels				
n/a	Ton			
Sorbent				
Lime	Ton	70,150	55.00	3.86
Chemicals/Catalyst				
Dibasic Acid	Ton	0	360.00	0.000
Utilities				
Electric Power	kW x10 <sup>3</sup>	20	0.050	1.00
By-products Credits				
Gypsum	Ton	0	3.00	0.00
Calcium Chloride	Ton		1.00	
Flyash	Ton	0	5.33	0.00
Waste Disposal Charges				
Lime	Ton	0	55.00	0.00
Sludge Removal	Ton	186,934	10.00	1.87
Subtotal Variable Cost				6.73
Total O & M Cost (Fixed + Variable)				8.10

### Lime Spray Dryer

<u>Power Plant Attributes</u>		<u>Units</u>	<u>Value</u>
Plant Capacity (net)		Mwe	300
Power Produced (net)		10 <sup>9</sup> kWh/yr	1.708
Capacity Factor		%	65.0%
Plant Life		yr	15
Coal Feed		10 <sup>6</sup> tons/yr	0.629
Sulfur in Coal		wt %	3.2%
Emissions Control Data	Units	SO2	NOx
Removal Efficiency	%	95.0%	TSP
Emissions Standard	lb/10 <sup>6</sup> BTU	1.20	PM10
Emissions Without Controls	lb/10 <sup>6</sup> BTU	5.01	
Emissions With Controls	lb/10 <sup>6</sup> BTU	0.25	
Amount Removed	Tons / Year	38,268	
		Current Dollars	Constant Dollars
Levelized Cost of Power		Factor Mills/kWh	Factor Mills/kWh
Capital Charge		0.1604 7.27	0.124 5.62
Fixed O & M Cost		1.293 1.04	1.000 0.80
Variable Operating Cost		1.293 5.10	1.000 3.94
Total Cost		13.41	10.37
Levelized Cost - SO2 Basis		Factor \$/ton Removed	Factor \$/ton Removed
Capital Charge		0.1604 324.69	0.124 251.01
Fixed O & M Cost		1.293 46.35	1.000 35.85
Variable Operating Cost		1.293 227.48	1.000 175.93
Total Cost		598.52	462.78
Levelized Cost - SO2 + NOx Basis		Factor \$/ton Removed	Factor \$/ton Removed
Capital Charge		0.1604 0.00	0.124 0.00
Fixed O & M Cost		1.293 0.00	1.000 0.00
Variable Operating Cost		1.293 0.00	1.000 0.00
Total Cost		0.00	0.00

**Saarberg-Holter (SHU)**

**CAPITAL COSTS (market base)**

Plant Size (Mw)	300.0
Capacity Factor	65.0%

	<u>\$x1,000,000</u>	<u>\$/kW</u>
<u>FGD System Titles</u>		
100 Raw Material Receiving and Handling System	5.3	17.7
200 Fuel Preparation and Storage System	0.0	0.0
300 Fuel and Oxidant Feed Handling System	0.0	0.0
400 Combustion / Steam Generation System	0.0	0.0
500 Combustion Modification Equipment	0.0	0.0
600 Fuel Gas Processing and Handling System	0.0	0.0
700 Power Generating System	0.0	0.0
800 SO <sub>2</sub> Removal System	8.1	27.0
900 NO <sub>x</sub> Removal System	0.0	0.0
1000 Particulate Removal System	0.0	0.0
1100 Flue Gas Handling System	6.4	21.4
1200 Raw Material Regeneration System	0.0	0.0
1300 By-Product Processing and Handling System	0.0	0.0
1400 Waste Handling System	0.1	0.4
1500 Common Support Systems	11.6	38.6
1600 Other Systems	6.8	22.6
A Total Process Capital	38.3	127.7
B General Facilities		
C Engineering & Home Office Fees (10% of TPC)	3.8	12.8
D Project Contingency (10% of A+B+C)	4.2	14.0
E Total Plant Cost (A+B+C+D)	46.4	154.5
F Allowance for Funds During Construction	0.9	2.9
G Total Plant Investment	47.2	157.4
H Royalty Allowance	NA	NA
I Preproduction Costs	2.6	8.8
J Inventory Capital	0.645	2.15
K Initial Catalyst & Chemicals	NA	NA
L Subtotal Capital (G+H+I+J+K)	51	168.4
M Cost of Construction Downtime	21	70
N Total Capital Requirement	72	238.6

**Saarberg-Holter (SHU)**

<u>Fixed O &amp; M Costs</u>		<u>Units</u>	<u>Quantity</u>	<u>\$ / Unit</u>	<u>\$(xM)/Yr</u>
Operating Labor		Mnhr/hr	27,040	23.00	0.62
Maintenance Labor					0.19
Maintenance Material					0.28
Administration / Support Labor					0.24
<b>Subtotal Fixed Costs</b>					<b>1.33</b>
 <u>Variable Operating Costs</u>					
<b>Fuels</b>					
n/a		Ton			
<b>Sorbent</b>					
Limestone		Ton	65,993	15.00	0.99
<b>Chemicals/Catalyst</b>					
Formic Acid		Lb	171,845	0.43	0.074
<b>Utilities</b>					
Electric Power		kW x10 <sup>3</sup>	35	0.050	1.76
<b>By-products Credits</b>					
Gypsum		Ton	0	3.00	0.00
Calcium Chloride		Ton		1.00	
Flyash		Ton	0	5.33	0.00
<b>Waste Disposal Charges</b>					
Lime		Ton	0	55.00	0.00
Sludge Removal		Ton	110,008	10.00	1.10
<b>Subtotal Variable Cost</b>					<b>3.93</b>
<b>Total O &amp; M Cost (Fixed + Variable)</b>					<b>5.25</b>