DE-FC22-93PC92642

# MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

## PROJECT PERFORMANCE AND ECONOMICS REPORT

### FINAL REPORT - VOLUME I of II

**NEW YORK STATE ELECTRIC & GAS CORPORATION**

# MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

LANSING, NEW YORK

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# ABSTRACT

*The intent of the Project Performance and Economics Report is to provide a comprehensive statement of the technical and economic results of the technologies demonstrated at the New York State Electric and Gas Corporation's (NYSEG) Milliken Station. Milliken Station is a 2 X 150 MW coal-fired electric generating plant owned by NYSEG and located in Lansing, New York. The Milliken Clean Coal Technology Demonstration project provided full-scale demonstration of a combination of innovative emission-reducing technologies and plant upgrades for the control of sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_x$) emissions from a coal-fired steam generator without a significant loss of efficiency. The FGD process used, developed by Saarberg-Hölter Umwelttechnik GmbH (S-H-U), is the only wet-limestone FGD process designed specifically to employ the combined benefits of low-pH operation, formic acid enhancement, single-loop cocurrent/countercurrent absorption, and in situ forced oxidation.*

*Combustion modifications were installed on both Milliken units for primary control of NOx emissions. The modifications consisted of replacing the existing conventional tangential firing systems with the Low NOx Concentric Firing Systems (LNCFS) furnished by ABB CE Services. Each system included new burners, windboxes and over-fir air systems.*

*Another element of the project was the addition of a high efficiency heat pipe air heater system, along with other equipment modifications, to maintain the station efficiency, while significantly reducing $SO_2$ and NOx emissions. The CAPCIS corrosion monitoring system was used in conjunction with the high efficiency air heater system to control flue gas temperature discharge temperature and prevent acid corrosion due to condensation. Also, the Plant Economic Optimization Advisor (PEOA), an on-line performance support system developed by DHR Technologies, Inc. was installed on both of the units. This 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 Project Performance and Economics Report details the effects of the technologies on station performance, reliability and operability and describes commercial applications and process economics. The report provides a detailed description of the demonstration program and test results, and an evaluation of the project's impact on wastes and by-products. Also presented are estimated costs for a commercial equivalent of the project's technologies, including documentation of the applications' cost parameters and process economics.*

# ACKNOWLEDGEMENTS

The Milliken Station Clean Coal Technology Demonstration Project was a cooperative effort. NYSEG, as the Host Utility, Co-funder and Project Manager extends its thanks to all of the organizations and individuals who worked together as a team to make the project a success. In particular, the U.S. Department of Energy, Co-funder; Empire State Electric Energy Research Corporation, Co-funder; Electric Power Research Institute, Co-funder; New York State Energy Research and Development Authority, Co-funder; CONSOL, Inc., Co-funder and Subcontractor; Saarberg-Hölter Umwelttechnik GmbH, Subcontractor; Stebbins Engineering and Manufacturing Company, Subcontractor; NALCO Fuel Tech, Subcontractor; ABB Air Preheater, Inc., Subcontractor; DHR Technologies, Inc., Subcontractor; and Parsons Energy and Chemicals Group, Engineer and Construction Manager.

# POINT OF CONTACT

For further information on the Milliken Clean Coal Technology Demonstration Project and/or the technologies being used, you may contact the following:

## DOE/FETC

| | |
|---|---|
| Name: | Dr. James Watts |
| Title: | Technical Project Officer - FETC |
| Organization: | US Department of Energy<br>Federal Energy Technology Center |
| Address: | CT-10, Mail Stop 920-L<br>Office of Clean Coal Technology<br>US Department of Energy/FETC<br>PO Box 10940<br>Pittsburgh, PA 15236-0940 |
| Phone Number: | (412) 892-5991 |

## PARTICIPANT

| | |
|---|---|
| Name: | Mr. James Harvilla |
| Title: | Project Manager |
| Organization: | New York State Electric & Gas Corporation |
| Address: | Corporate Drive<br>Kirkwood Industrial Park<br>PO Box 5224<br>Binghamton, NY 13902-5224 |
| Phone Number: | (607) 762-8630 |

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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 |
| $Ca^{+2}$ | Calcium ion |
| $CaCl_2$ | Calcium chloride |
| $CaCO_3$ | Calcium carbonate (limestone) |
| CAPCIS | Corrosion and Protection Centre Industrial Services |
| CaO | Quicklime |
| $CaSO_4$ | Calcium sulfate |
| $CaSO_4 \bullet 2H_2O$ | 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 |

| | |
|---|---|
| CFD | Computational fluid dynamic |
| CFR | (US) code of Federal Regulations |
| CFS | Concentric Firing system |
| $Cl^-$ | Chloride ion |
| CKM | Chemical kinetics model |
| CO | Carbon monoxide |
| $CO_2$ | Carbon dioxide |
| COI | Contaminant of Interest |
| CPRW | Coal pipe runoff water |
| $Cr^{+6}$ | 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 |
| $D_{50}$ | 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 | $NO_x$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. |
| | |
| $H^+$ | Hydrogen ion |
| $H_2$ | Hydrogen |
| $H_2O$ | Water |
| HCl | Hydrochloric acid |
| HCOOH | Formic acid |
| Hg | Mercury |
| HQ | Hazard quotient |
| $HSO_3^-$ | 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 $NO_X$ 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 |

| | |
|---|---|
| $NH_2CONH_2$ | Urea |
| $NH_3$ | Ammonia |
| Ni | Nickel |
| NIST | National Institute….. |
| NMHC | Non-methane hydrocarbons |
| NO | Nitric oxide |
| $NO_2$ | Nitrogen dioxide |
| $NO_X$ | Oxides of nitrogen |
| NOAA | National Oceanographic and Atmospherics Administration |
| NSPS | New Source Performance Standards |
| NTU | Number of transfer units |
| NYSDEC | New York State Department of Environmental Conservation |
| NYSDOT | New York State Department of Transportation |
| NYSEG | New York State Electric & Gas Corporation |
| | |
| $O_2$ | Oxygen |
| $O_3$ | 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 concentratrion 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 |
| $PM_{10}$ | Particulate matter less than or equal to 1 0 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 |
| $SO_2$ | Sulfur dioxide |
| $SO_3$ | Sulfur trioxide |
| $SO_4^=$ | 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) |
| | |
| $^oF$ | Degrees Fahrenheit |
| ft | Feet |
| $ft^2$ | 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 |

| | |
|---|---|
| kWh | Kilowatt hour |
| | |
| lb/hr | Pounds per hour |
| lb/MM Btu | Pounds per million British thermal units |
| liters/hr | Liters per hour |
| | |
| $m^2$ | square meters |
| mA | Milliampere |
| MGD | Millions gallons per day |
| mg/l | Milligrams per liter |
| $mg/m^3$ | 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 |
| | |
| $\mu g/m^3$ | 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 |
| $CaCl_2$ | Calcium chloride |
| CaCO3 | 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 |
| $CO_2$ | Carbon dioxide |
| | |
| Densadeg® | Infilco Degremont's proprietary thickener-clarifier |
| DOE | US Department of Energy |
| Dowtherm A® | Proprietary eutectic mixture of diphenyl oxide ($C_{12}H_{10}O$ and biphenyl ($C_{12}H_{10}$) |
| 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 |
| ESPert™ | 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 $NO_X$ Concentric Firing System 3, ABB-CE's low $NO_X$ 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 |
| NH3 | Ammonia |
| NMHC | Non-methane hydrocarbons |
| NO | Nitrogen oxide |
| $NO_2$ | Nitrogen dioxide |
| NOx | Oxides of nitrogen |
| $NO_X$OUT® | Process, by Nalco Fuel Tech, urea-based chemical and mechanical system for cost-effective $NO_X$ reduction |
| $NO_X$OUT A® | Proprietary urea solution for $NO_X$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 |
| SEMPLATE™ | Stebbins Engineering's proprietary ceramic tile material |
| S-H-U | Saarberg-Hölter Umwelttechnik GmbH |
| SNCR | Selective non-catalytic reduction |
| $SO_2$ | 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 eco-systems |
| US | United States |

## EXECUTIVE SUMMARY

In May 1991 New York State Electric & Gas Corporation (NYSEG) applied to the US Department of Energy (DOE) for partial funding of the $159 million Milliken Clean Coal Technology Demonstration (MCCTD) Project from the Clean Coal Technology IV program. This program, a team effort between the federal government and coal users, will help ensure the nation uses this abundant domestic resource wisely and in an environmentally responsible manner. In September of 1991, the Milliken project was chosen as a successful applicant. The MCCTD was one of nine clean coal projects selected for funding by the DOE. A Cooperative Agreement for the project was executed between NYSEG and the DOE on October 20, 1992 (DE-FC22-93PC92642).

The Milliken Clean Coal Technology Demonstration Project was constructed at NYSEG's Milliken Station located in Lansing, Tompkins County, New York. This plant is one of the top 20 most efficient steam electric generating stations operating in the United States. The project achieved significant reductions in acid gas emissions with virtually no change in station efficiency by demonstrating technologies that are technically and economically viable in a retrofit application. It provides cost and performance data from a commercial-scale application to demonstrate the viability of this technology for both new and retrofit utility applications.

The total project cost was $158,607,807. The DOE's share was $45,000,000. NYSEG secured additional cofunding agreements with:  CONSOL, Inc., Empire State Electric Energy Research Corporation (ESEERCO), Electric Power Research Institute (EPRI), and New York State Energy Development Authority (ERDA).

The major technology vendors that joined NYSEG as an integrated team and their associated technologies are as follows:

- Saarberg-Hölter-Umwelttechnik (SHU) - FGD Process Design
- Stebbins Engineering and Manufacturing Company (Stebbins) - Tile Lined Absorber Design and Fabrication
- Nalco Fuel Tech - SNCR Design and Equipment Supply
- ABB Air Preheater, Inc. - Heat Pipe Air Heater Design and Fabrication
- DHR Technologies, Inc. - Design and Installation of Plant Economic Optimization Advisor (PEOA) expert computer system

The project provides full-scale demonstration of a combination of innovative emission-reducing technologies and plant upgrades for the control of sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_X$) emissions from a coal-fired steam generator, without a significant loss of efficiency.  There are two coal-fired units, Units 1&2, at Milliken Station.  They are Combustion Engineering pulverized coal-fired units which are rated at a nominal 150

MW each and operate under balanced draft mode. Each unit is tangentially fired with four elevations of burners at each of the four corners. Unit 1 was completed in 1955 and Unit 2 was completed in 1958.

The overall project goals were:

- To achieve 98% $SO_2$ removal efficiency using limestone while burning high-sulfur coal.
- To achieve up to 70% $NO_X$ reductions using the NOxOUT® selective non-catalytic reduction (SNCR) technology in conjunction with combustion modifications.
- To minimize solid wastes by producing marketable by-products (commercial-grade gypsum, calcium chloride, and fly-ash).
- To achieve zero wastewater discharge.
- To maintain station efficiency by using a high efficiency heat pipe air heater system and a low power consuming scrubber system.

Construction began in April, 1993. The Unit 1 electrostatic precipitator upgrade and combustion modifications were placed in operation in September, 1993. The Unit 2 electrostatic precipitator upgrade, heat pipe air heater, and combustion modifications were placed in operation in December, 1994. The Unit 2 scrubber module became operational in January, 1995. The Unit 1 scrubber module began scrubbing in June, 1995. The demonstration phase of the MCCTD project officially began on January 17, 1995 and was completed in May, 1998.

## SHU FGD PROCESS

The Saarberg-Hölter Umwelttechnik (SHU) process was used to reduce $SO_2$ emissions by as much as 98%. The SHU process is the only developed wet limestone flue gas desulfurization (FGD) process which is designed specifically to employ the combined benefits of low-pH operation; formic acid enhancement; single loop, cocurrent/countercurrent absorber; and in-situ forced oxidation. In the SHU process, the flue gas is scrubbed with a limestone slurry in a cocurrent/countercurrent absorber vessel that does not contain packing or grid work. This significantly reduces the potential for plugging and erosion and reduces the energy consumption of the induced draft (ID) fans. The SHU slurry is able to be maintained at a low pH by adding formic acid, which acts as a buffer, to the limestone slurry. A slipstream (the bleed) is processed for recovery of commercial grade gypsum and recycled to the process. A portion of the recycle stream (the FGD blowdown) is processed to control the concentration of chlorides in the absorber, producing a byproduct calcium chloride brine solution. The project demonstrated the production of excellent and consistent quality gypsum for use in wallboard manufacturing and marketable grade calcium chloride brine. This is the first US demonstration of the SHU process and includes the innovative space-saving design feature of a tile-lined, split-flow absorber constructed below the flues, an advantage for retrofit on existing plants where space is at premium. The S-H-U FGD process was installed on both Units 1 and 2 with common auxiliary equipment.

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% $SO_2$ 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 operated for more than 30,000 hours.

Except for scheduled outages, unit availabilities held close to 100% and capacity factors generally held between 70% and 80% over the course of the demonstration. Unit thermal efficiencies hovered around 35% for both units. FGD system availabilities held fairly constant at close to 100%. $SO_2$ 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 course of the demonstration.

While the FGD systems have generally performed well throughout the demonstration, they have not been completely problem free. The absorbers have experienced a greater than expected deposition of solids on the absorber internals, slurry piping, and dewatering equipment. The units were inadvertently operated for extended periods of time at lower than design gypsum solids concentrations. This operation, at supersaturation, results in a lower inventory of seed crystals in the slurry, causing an increase in uncontrolled gypsum growth on equipment surfaces. In addition, pieces of rubber lining from the absorber modules' internal turning vanes have been found plugging absorber nozzles and hydrocyclone apexes. Operating changes were 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. Also, suction screens were installed for several of the absorber recycle pumps. These changes resulted in greatly improved operability of the hydrocyclones and centrifuges and have greatly reduced the amount of buildup and plugging in the absorbers.

The FGD blowdown stream is processed through a pretreatment system for removal of suspended solids and heavy metals, followed by a brine concentrator system for recovery of byproduct calcium chloride brine. The brine concentrator system experienced numerous operating problems throughout the demonstration. These problems included plugging and scaling of evaporator tubes, high suspended solids in the byproduct brine, high vibration of the vapor compressor and corrosion of vapor compression system components. System design changes were implemented to solve the vibration, corrosion and suspended solids problems. Changes to system chemistry made to alleviate scaling and plugging, however, resulted in byproduct brine which did not meet contract specifications. 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.

A formal parametric testing program was conducted to evaluate absorber module chemistry for limestone grind, formic acid concentration, and variations in recycle slurry operation relative to $SO_2$ removal, L/G ratio, pressure drop, formate loss, oxidation air utilization and gypsum and chloride brine quality. Low sulfur coal (1.6% S) parametric tests found that $SO_2$ removal ranged from 30%, when using only two spray headers without formic acid, to 98%, when using all seven spray headers with formic acid (nominally 800 ppm). $SO_2$ removals increased with increasing L/G. More $SO_2$ removal was achieved when a higher percentage of the total slurry was sprayed in the countercurrent section. The effect of countercurrent L/G on $SO_2$ removal diminished with increasing formic acid concentration. $SO_2$ removal was increased significantly by formic acid but the amount of additional removal showed a tendency to level off with increasing formic acid concentration, suggesting that concentrations of formic acid higher than those tested would produce diminishingly smaller improvements in $SO_2$ removal. Higher $SO_2$ removal was observed using finer grind limestone than with coarser grind. The average difference in $SO_2$ removal between the two grind sizes was 2.6 percent (absolute). The effect was greatest at the intermediate formic acid concentration. When compared on an equivalent L/G basis, more $SO_2$ was removed during the high velocity tests than during the design 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. The pressure drop across the absorber was a function of the number of countercurrent spray headers operating. The cocurrent spray headers had no significant effect on the pressure drop. Mass transfer increased with increasing L/G, but the effect was not always a linear function of L/G. Formic acid increased the mass transfer; however, the amount of increase diminished with increasing formic acid concentration. 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.

Laboratory analyses performed on gypsum samples taken during the testing indicate that the gypsum purity was relatively constant ranging from 96.1% to 97.8% gypsum, regardless of the operating conditions, demonstrating that the ability to make a marketable gypsum is relatively insensitive to changes in the operating conditions.

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. Table 1 summarizes the SHU process' economics for a 300 MW commercial plant. The table provides values for levelized cost of power on cost per kW and cost per ton of $SO_2$ removed bases, in both current and constant dollars.

**Table 1**
**SHU FGD Process Economics**
300 MW Commercial Facility

| | | Current Dollars | | Constant Dollars | |
|---|---|---|---|---|---|
| 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 |
| | | | | | |
| Levelized Cost - SO2 Basis | | Factor | $/ton Removed | Factor | $/ton Removed |
| 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 |
| | | | | | |

At the time that this Project Performance and Economics Report was published, results of the Design and High Sulfur Coal Testing and Evaluation Programs had not been reported. When available, the program results will be presented in a topical report.

## STEBBINS TILE ABSORBER

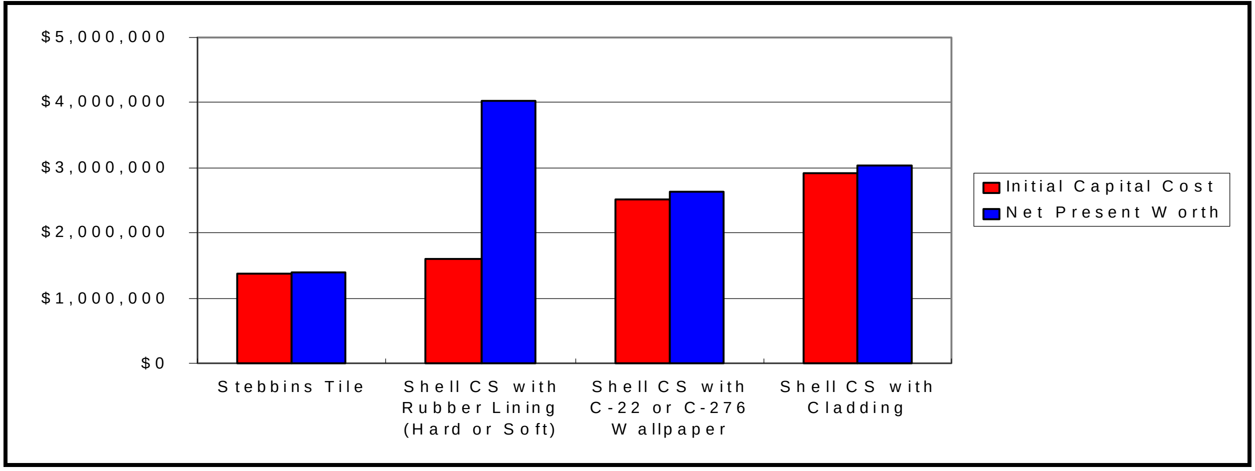
Milliken's FGD system absorber is of Stebbins ceramic tile reinforced concrete construction. The Stebbins ceramic tile system offers several advantages to the utility marketplace including lower life-cycle costs, increased reliability, reduced maintenance costs, capability for online repair of leaks in exterior walls from outside the absorber vessel, and the ability to be constructed between existing structures without having to provide a large amount of space for cranes, an advantage for projects with limited construction access. The SHU process provided a harsher environment in which to demonstrate the durability of Stebbins tile than previous applications. In addition to having higher gas velocity, the SHU recycle slurry is more acidic, has a higher chloride concentration, and includes an organic acid buffered chemistry. SHU's cocurrent/countercurrent design also requires an interior wall with both sides exposed to the process (and thereby not accessible for maintenance except during boiler outages).

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. Inspection after three years of operation found that the Stebbins ceramic tile lined absorbers and the tile grout were in excellent condition with no obvious erosion or deterioration. In order to further substantiate the viability of the Stebbins construction a test module was constructed at NYSEG's Kintigh Station. This three-year testing program confirmed that leak repair is simple and effective. The effects of leakage on concrete appeared minimal, tile and mortar wear were undetectable and maintenance was not required. Because the demonstration project was scheduled for only three years of operation, the total potential life-span for the Stebbins tile could not be assessed. However, the viability of the split module concept was fully demonstrated. The combination of the durability and reliability already demonstrated within the non-FGD industrial market and the Milliken Station demonstration should enhance Stebbins' ability to effectively market this product to FGD vendors and utilities.

In addition, 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.

Figure 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 1**
**Absorber Materials Cost Comparison**



## ABSORBER MIST ELIMINATORS

Each Milliken absorber module is equipped with two-stage mist eliminators (ME's). A droplet carry-over testing program was conducted to evaluate mist eliminator performance. Droplet tests were conducted at the inlet to the first stage mist eliminator of 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. 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.

## HEAT PIPE AIR HEATER

In order to counter the loss in plant efficiency due to the FGD system retrofit, a high efficiency heat pipe air heater system was installed on Milliken Unit 2. A heat pipe unit uses carefully selected liquids, sealed in tubes, as the heat transfer medium. One portion of each tube is in the flue gas stream and the rest of the tube is in the air stream. The liquid in the tube evaporates in the hot portion; then the vapor flows to the cold end, where it condenses; and the condensate flows back to the hot end. The need for special air seals and the associated potential for air heater leakage, as required for conventional air heaters, is eliminated with this design. Because of the high efficiency of these units, the temperature of the combustion air can be increased, increasing the efficiency of the plant.

Detailed tests and analyses indicated that the thermal performance of the heat pipes is about the same as the original Ljungstrom-type air heaters. The goal of a 20 $^0$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, improving the boiler heat rate by greatly reducing the fan power requirements for the system. At full boiler load, the fan power savings averaged 778 KW or about 0.49% of the gross load.

Cold-end fouling of the heat pipes was 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 boiler low load to a minimum of 80 MW. This practice helps to avoid excessively low cold-end temperatures which increase fouling.

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).

Table 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 napthalene 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 2**
**Heat Pipe/Air Heater Cost Comparison**
**($ X $10^6$)**

| | **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 | |

## COMBUSTION MODIFICATIONS

Combustion modifications were installed on both Milliken units for primary control of $NO_x$ emissions. These modifications consisted of replacing the existing conventional tangential firing systems with the Low $NO_x$ Concentric Firing Systems-Level 3 (LNCFS-3) furnished by ABB CE Services. Each system included new burners, wind boxes and over-fire air systems. The LNCFS maximizes the $NO_x$ reduction capabilities of existing tangential firing systems while minimizing unit modification. The LNCFS uses a combination of two techniques to reduce $NO_x$: bulk furnace staging and early controlled coal devolatilization. Bulk furnace staging takes a portion of the combustion air, which is introduced at the fuel burning zone, and diverts it to retard air and fuel mixing. The LNCFS maximizes the bulk staging concept by using both overfire air and concentric firing. Staged combustion is produced by introducing a portion of the secondary air, called overfire air, above the primary firing zone. This is accomplished with a close-coupled overfire air system, in which the overfire air nozzles are located in the top elevations of the main windboxes, and in a new separate overfire air windbox, which is installed above the existing windbox. The concentric firing system re-directs the secondary air which is admitted in the main firing zone, diverting it away from the coal stream. In this manner, combustion stoichiometry is reduced by preventing the fuel stream from entraining with the air stream during the initial stages of combustion. Fuel nitrogen conversion is reduced, while maintaining appropriate oxidizing conditions along the furnace walls. The introduction of air in the concentric firing circle is accomplished with the installation of offset air nozzles. Another important design feature incorporated into the LNCFS is the technique of early fuel ignition. Initiating the combustion point very close to the fuel nozzle produces a stable volatile matter flame which is more easily controlled under sub-stoichiometric firing conditions. A two-piece "flame attachment" type coal nozzle tip is used to promote this strong primary flame.

A testing program was conducted to evaluate the effectiveness of the LNCFS-3 burner retrofit in reducing $NO_X$ emissions while maintaining high combustion efficiency and acceptable fly ash loss-on-ignition (LOI). The coal used was a high volatile (37%-38% dry volatile matter), medium sulfur (1.6%-2.0% dry sulfur) Pittsburgh Seam coal. The tests found that at full boiler load (145-150 MW) and 3.0%-3.5% economizer $O_2$, the LNCFS-3 system lowered $NO_X$ 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 $O_2$, the LNCFS-3 system lowered $NO_X$ 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 $O_2$ 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.

## PCGC-3 COMBUSTION MODEL

The project included an evaluation of the PCGC-3 combustion model, 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 (ACERC). The model 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 $NO_X$ reduction achieved through its use.

The evaluation included a study performed by ACERC using the Milliken Station Unit #2 furnace to compare test data with predictions from the coal-qualified PCGC-3 combustion code to assess the reliability of the model in predicting furnace behavior. The study concluded that full-scale furnace testing with sensitive laboratory instruments can be successful; that 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's; that coal devolatilization rate constants have a significant influence on the predicted results, especially in the near-field; that 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 $NO_X$ 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. In summary, the study found 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.

## $NO_x$OUT® SNCR System

In addition to the LNCFS installed on both units for primary $NO_x$ emissions control, the $NO_x$OUT® selective noncatalytic reduction (SNCR) technology was to be installed on Unit 2 to provide a further reduction in $NO_X$ emissions. The $NO_X$OUT® process achieves $NO_X$ reduction by the reaction of $NO_X$ with urea injected into the post-combustion zones of the boiler. The project intended to demonstrate a $NO_X$ emissions reduction of 30% or more over that achieved with combustion modifications alone, to demonstrate cost effectiveness of the process for $NO_X$ reduction and to determine the effects of these $NO_X$ reduction technologies on air heater, electrostatic precipitator (ESP) and scrubber operations and on fly ash quality.

The NOxOUT® demonstration was eventually relocated to Penelec's Seward Station due to concerns over potential air heater fouling. Because Seward Station is not equipped with low $NO_x$ burners the project was not able to demonstrate reductions $NO_X$ emissions over that achieved with combustion modifications alone. Also, because Seward Station is not equipped with an FGD system, the project was not able to determine the effects of the NOxOUT® technology on scrubber operations. As of this writing results of the testing program conducted at Seward have not been published. When available the results of this demonstration will be included in a future topical report.

## 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. 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 PEOA system 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 evaluate key emissions data parameters, including $NO_x$, $SO_2$, $O_2$, CO, $CO_2$, 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 employ the optimization features to evaluate various operation 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.

Initial evaluation of the PEOA system included two series of tests, one short-term (about 3 hours) and one long-term (48 hours). Results of these tests were promising but inconclusive. Both tests indicated that PEOA could maintain $NO_X$ and Loss on Ignition (LOI) levels within their designated limits. Though PEOA's ability to increase plant efficiency was not demonstrated over the long term, some positive short term improvements were observed. The short-term test showed improvement in both gross and net generation for approximately 20 minutes after which they settled to approximately their initial steady state levels. The long-term test showed an increase of approximately 1 MW in both gross and net generation outputs, about a 0.84% increase in energy sales income. PEOA provided some recommendations during the long-term test which 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 and the system was re-tested. As of this writing results of the performance testing of the modified PEOA system have not been published. When available this information will be included in a future topical report.

## ESP UPGRADE

The project also included upgrading the station’s electrostatic precipitators (ESP) to accommodate production of commercial grade gypsum by the FGD system. Originally, each unit’s particulate control system consisted of two ESP’s in series, stacked one on top of the other. Each ESP 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 and a third field was added. Six new computer controlled TR sets were installed replacing the originals. With a 16-inch plate spacing, the modified units are smaller and require less energization power. The SCA at full load decreased from 392 to 175 $ft^2$ 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.

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 performs better than the original unit at a lower operating (power) cost. Overall particulate 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.

After the Unit 2 ESP upgrade was installed, the performance of an ESP computer model (ESPert™) was evaluated by comparing the predicted performance with actual ESP performance. This evaluation shows 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 adequately predict the effect of the wide plate spacing. Diagnostic messages confirmed that the operating conditions for this ESP are outside the range expected by ESPert™. Additional tests with other coals are needed to define the effects of wide plate spacing.

## MILLIKEN STATION ENVIRONMENTAL MONITORING PROGRAM

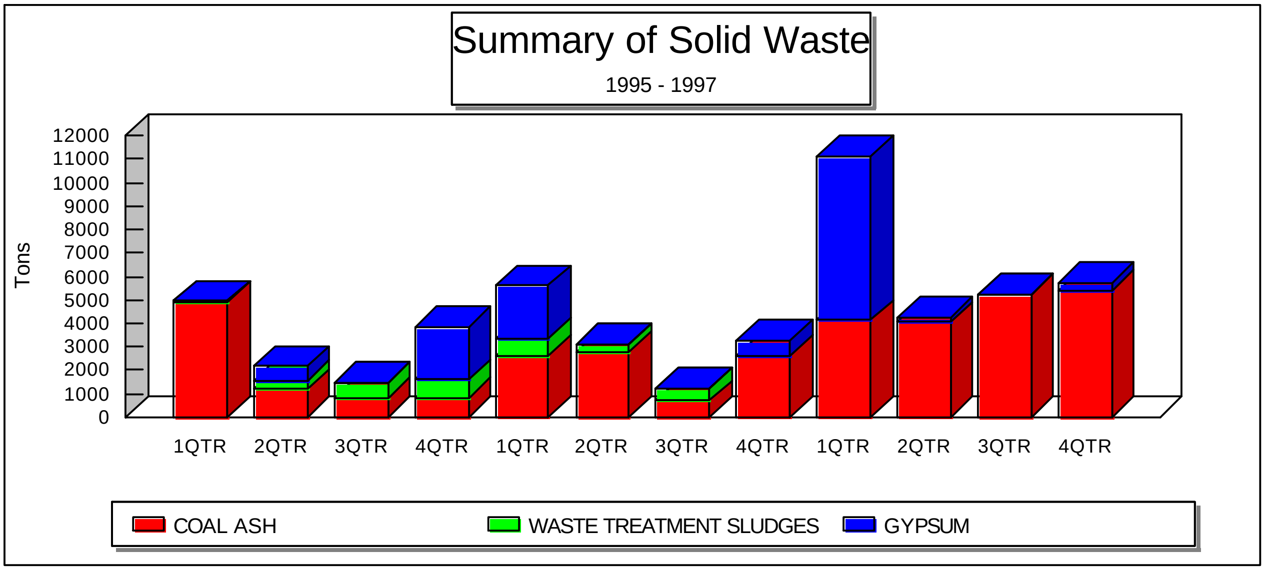
An environmental monitoring program was conducted at Milliken to meet the compliance monitoring requirements of the various permitting agencies and to track the performance of the demonstration technologies. The program monitored stack emissions, ambient air quality, solid waste production, disposal, and sales, and noise pollution.

The installation of Low $NO_X$ Concentric Firing System Level 3 (LNCFS-3) burners to reduce $NO_X$ emissions while maintaining high combustion efficiency and acceptable fly ash loss on ignition (LOI) reduced annual $NO_X$ emissions from 0.61 lbs/mmBtu for baseline operations to 0.39 lbs/mmBtu for post retrofit operations, a 36% reduction in $NO_X$ emissions. Upgrades of the ESP on both units reduced the average particulate penetration from 0.22% to 0.12% while reducing the ESP power consumption by 25%. The flue gas desulfurization system achieved an average $SO_2$ removal efficiency over the monitoring period of approximately 88%, including testing periods in which operating conditions were varied to determine effects on removal efficiencies.

The ambient levels of $SO_2$, $NO_2$, $O_3$, TSP and $PM_{10}$ at all monitoring sites were found to be below ambient air quality standards throughout the entire 4-year ambient monitoring program. Analysis of 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, revealed significant changes to the ambient air quality. The ambient $SO_2$ levels showed a reduction by an average of 40-50% over the course of the study. The ambient $NO_2$ levels were reduced by an average of 10-15% at the North and South monitoring sites, while very little change was observed in the $NO_2$ levels at the East site over the same period. Ambient ozone levels appeared to be reduced slightly, while no discernible changes were observed in the TSP and $PM_{10}$ ambient levels.

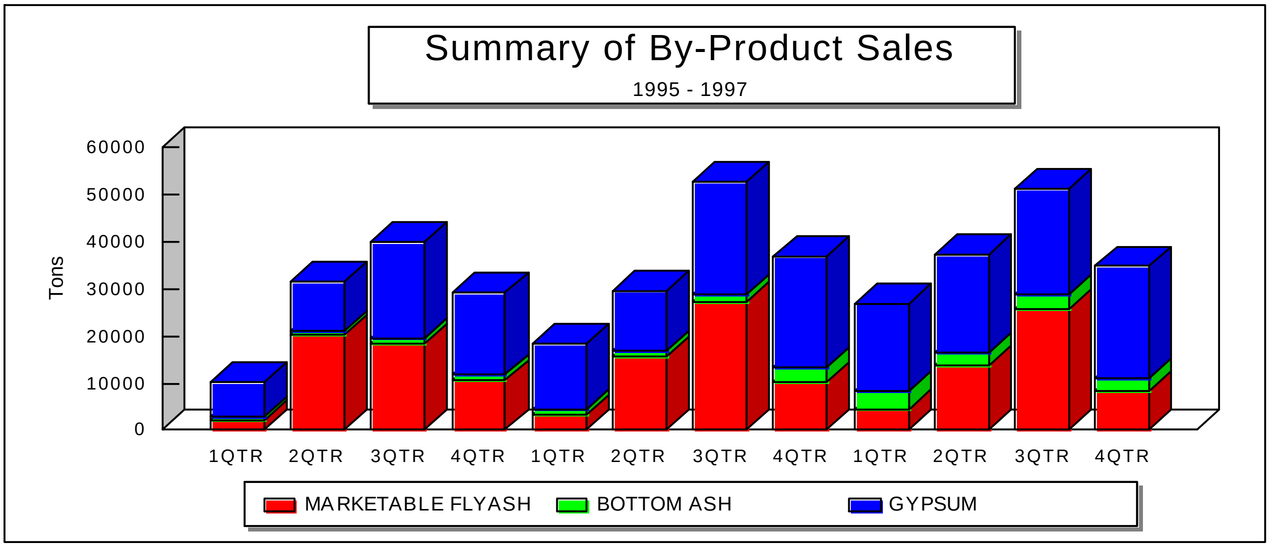
Solid waste generation by Milliken Station during 1995 - 1996 is depicted on Figure 2. Fly ash disposal was initially high due to the tuning of the LNCFS-3 burners. Fly ash disposal dropped off during the course of the year as optimization of the burners was finalized, allowing more of the fly ash to be sold. 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 2**



By-product marketing activity during 1995 - 1996 is depicted on Figure 3. 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 with the burner system increased, 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.

**FIGURE 3**



Noise measurements taken during the periods of July 20-23, 1992 and August 28-30, 1995 for baseline and project operational conditions, showed that only at one out of seven locations was the noise from Milliken readily discernible during both daytime and nighttime periods and that an increase in residual noise levels due to the Milliken CCTD project occurred only at the one monitoring location, where the increase was 1 dBA. No instances of annoying tonal noise were identified. The CCTD project met the environmental noise criteria of the special permit conditions.

## AIR TOXICS & 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 $SO_2$, $NO_X$ and particulate control systems. Removal efficiencies were determined for key air toxic compounds (Hg, Ni, As, Be, Cd, $Cr^{+6}$ , BaP, dioxins and furans). A system mass balance was developed for the metals.

The ESP was found to be 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 were in good agreement with coal input levels. From comparisons with coal input and flyash levels, selenium results for the ESP inlet and ESP outlet were 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 believed that sulfur interferences were the main source for the low biases associated with the selenium analytical results. 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 were 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/$10^6$ 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 used by the FGD process, which can have formaldehyde as an impurity. On the other hand, stack formaldehyde sample and field blank levels were similar.

ESP outlet $SO_3$ 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.

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 were seen for trace and major elements (including anion precursors) existing in the ESP outlet/FGD inlet flue gas at levels above 1 lb/$10^{12}$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%.

## MERCURY SPECIATION

A utility-scale field evaluation was conducted of four techniques for mercury speciation, the Ontario-Hydro method, the TRIS Buffer method, EPA Method 29, and Frontier Geosciences' solid sorbent scrubber technique. For the FGD outlet/stack location, excellent agreement among the Frontier Geoscience, Ontario-Hydro and TRIS Buffer measurements was obtained for Hg(0) and Hg(II). Hg(0) results ranged from 2.45-2.94 µg/$Nm^3$ (excluding Method 29) and Hg(II) results ranged from 0.15-0.35 µg/$Nm^3$ (excluding Method 29). Good to excellent agreement existed among Frontier, Ontario-Hydro, TRIS and EPA Method 29 for total mercury with results ranging from 2.66-3.29 µg/$Nm^3$. For the ESP outlet/FGD inlet, excellent agreement among Frontier, Ontario-Hydro, and TRIS was obtained for Hg(0) with levels ranging from 2.28-2.70 µg/$Nm^3$. The Ontario-Hydro and TRIS Buffer values were in good agreement for Hg(II); and Ontario-Hydro, TRIS and EPA Method 29 were in excellent agreement for total mercury. In comparison with the Ontario-Hydro and TRIS Buffer results, the EPA Method 29 mercury speciation values exhibited a high bias for Hg(II), and a low bias for Hg(0). There was 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.

## MILLIKEN-POST RETROFIT "TRUE" EVALUATION

The Milliken project 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 installation 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 FGD system to mitigate transferal of toxic materials from the plant site to the ambient environment. 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 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 bio-accumulated 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 eco-toxicological 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.

## MILLIKEN BY-PRODUCT UTILIZATION STUDIES

Flyash, which is marketed as concrete additive, can be adversely affected by the installation of the Low $NO_x$ Concentric Firing System (LNCFS) and the Selective Non-Catalytic Reduction (SNCR) process. Increased carbon and ammonia concentrations can result in unmarketable ash. It was assumed that the ash property most influenced by the use of low $NO_X$ burners was the LOI. To confirm this assumption, ash samples taken before and after the low $NO_X$ burner conversion were processed through the suite of tests required by the ASTM C618 protocol. The 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 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. Daily data on fly ash quality and $NO_X$ emissions gathered over a five-year (1992-1996) period demonstrated that a 39% reduction in $NO_X$ was achieved using LNCFS-3 low $NO_X$ 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-$NO_X$ 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.

Two new by-products were generated as a result of the operation of the FGD system: gypsum and calcium chloride brine. Separate studies conducted 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 calcium chloride study found that $CaCl_2$ is an undifferentiated commodity chemical with well-established, mature markets. The principal uses/markets for $CaCl_2$ 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. $CaCl_2$ 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%. Much of the $CaCl_2$ sold is in the form of 32%-38% brine, which is prohibitively expensive to transport over extended distances. The study concludes that while excess $CaCl_2$ production capacity does exist, utilities can capitalize on niche market opportunities if they produce by-product $CaCl_2$ in an area close to the market and/or centralized distribution point, and at a delivered price competitive with current suppliers. At a minimum, utilities should plan to produce $CaCl_2$ brines which are at least 32% $CaCl_2$ 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. If a utility is considering installing an FGD process and associated equipment to generate by-product $CaCl_2$ 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 study found a current demand in the United States of 26 million short tons of gypsum per year, including a chemical (by-product) gypsum market of about 0.75 million short tons per year. About half of the chemical gypsum is produced in FGD units. 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 may 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 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.

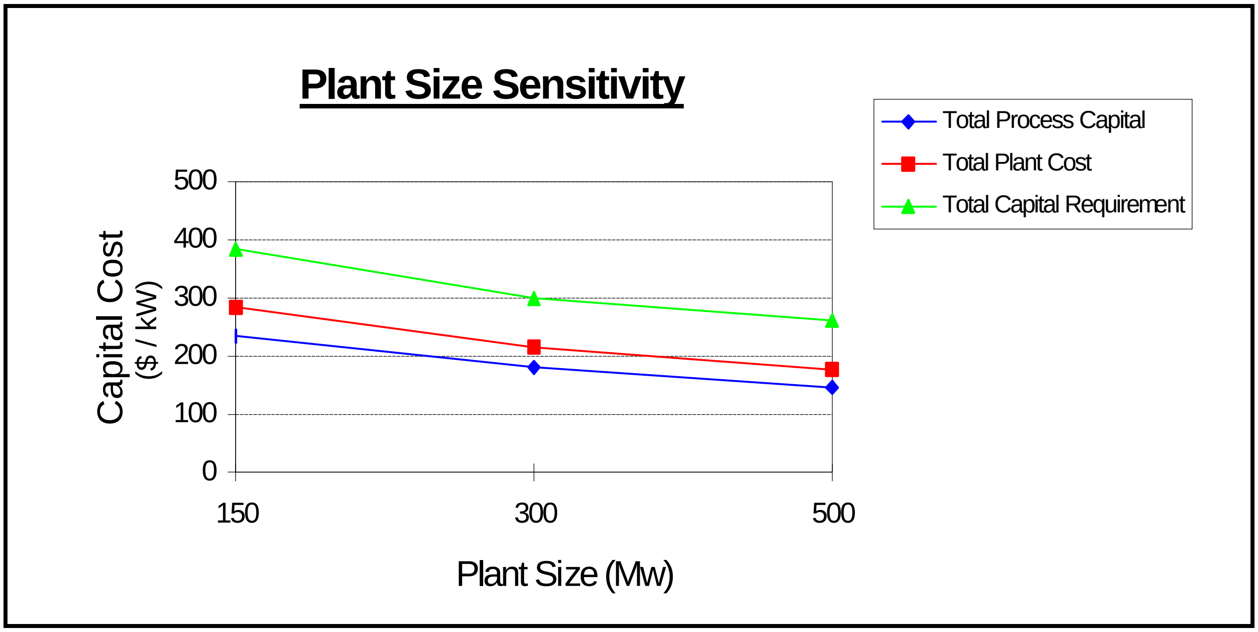
The technical feasibility of substituting FGD gypsum for natural gypsum in traditional applications including wallboard and cement manufacture, as an agricultural soil conditioner/supplement, and in the preparation of both building and specialty plasters, has been demonstrated. With respect to the wallboard 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. 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.

Economic evaluations indicate that 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.

When plotted in $/kW vs. unit size, as shown in Figure 4, total cost trends decrease markedly, demonstrating a clear and significant economy of scale. On a cost per kW basis, Total Capital Requirements for a FGD retrofit similar to Milliken Station can be expected to range from 385/$/kW for a 150 MW plant to 260/$/kW for a 500 MW plant.

**FIGURE 4**



# 1.0 INTRODUCTION

## 1.1 PURPOSE OF THE PROJECT PERFORMANCE AND ECONOMICS REPORT

The purpose of the Project Performance and Economics Report is to consolidate for public use all relevant nonproprietary information on the project, other than that already included in the Public Design Report (Volume 1 of the Final Report), which is the other major report required of all CCT projects.

Although the Project Performance and Economics Report is limited to nonproprietary data, it should contain sufficient information to provide a technical and economic overview of the project. It should serve as the primary reference for parties interested in the technology to determine the achievements of the project and to assist them in assessing the technical and economic applicability of the technology to their particular situations.

The Project Performance and Economics Report contains a comprehensive description of the total work performed under the cooperative agreement between the DOE and NYSEG. The report summarizes all relevant reports generated previously, and contains references to these reports. It discusses the background of the project, changes to the design made after the Public Design Report was issued, the technical accomplishments, the process economics, the environmental performance, and the applicability of the demonstrated technology. The report describes the investigations undertaken and the results obtained. The report gives NYSEG's view of the technical status of the processes demonstrated and the plans for commercialization and marketing. It provides adequate technology transfer and scaleup information to assist the private sector in judging commercial potential and making informed decisions on commercial readiness. Additionally, the report provides information to assist federal, state, and local authorities in making sound policy and regulatory decisions regarding commercial deployment of the clean coal technology covered in the report.

## 1.2 OVERVIEW OF THE PROJECT

### 1.2.1 BACKGROUND AND HISTORY OF THE PROJECT

In May of 1991, New York State Electric & Gas Corporation (NYSEG) applied to the US Department of Energy for partial funding of the $159 million project from the Clean Coal Technology IV program. This program, a team effort between the federal government and coal users, was designed to help ensure that the nation uses this abundant domestic resource wisely and in an environmentally responsible manner. In September of 1991, the Milliken Clean Coal Technology Demonstration (MCCTD) project was chosen as a successful applicant. A Cooperative Agreement was executed between NYSEG and the DOE on October 20, 1992. Construction began in April, 1993. The following research organizations provided cofunding and technical collaboration and support to the project: Electric Power Research Institute (EPRI), New York State Energy Research and Development Authority (NYS ERDA), Empire State Electric Energy Research corporation (ESEERCO), and CONSOL, Inc.

The Unit 1 electrostatic precipitator upgrade and combustion modifications were placed in operation in September, 1993. The Unit 2 electrostatic precipitator upgrade, heat pipe air heater, and combustion modifications were placed in operation in December, 1994. The Unit 2 scrubber module became operational in January, 1995. The Unit 1 scrubber module began scrubbing in June, 1995. The demonstration phase of the MCCTD project officially began on January 17, 1995 and was completed in December, 1998.

### 1.2.2 PROJECT ORGANIZATION

The MCCTD project was managed within the Generation Department of NYSEG's Electric Business Unit. A fully dedicated project management core team (see figure 1.2-1) was supplemented using corporate resources such as legal, accounting, purchasing, training, quality assurance, contract administration, research and development, and public information. Technical support was provided from the existing matrix organization. An architect engineering firm (Parsons Power Group, Inc.) was selected through competitive bidding to supplement administrative, engineering and construction management efforts.

Mr. Vincent W. Rider, Vice President - Electric Generation was the executive sponsor of the MCCTD project. Mr. Rider provided a direct line of communication to NYSEG's executive management. Mr. Rider was succeeded by Mr. J.K. Smith as executive sponsor in 1995.

The project was managed by a NYSEG Project Manager, Mr. Dennis T. O'Dea. Mr. O'Dea was the principal contact with DOE for matters regarding the administration of the Cooperative Agreement between NYSEG and DOE. This included the responsibility to coordinate the activities of support and team members to ensure successful completion of project objectives. Mr. O’Dea was succeeded by Mr. James J. Harvilla as NYSEG Project Manager in 1997. The DOE Contracting Officer was responsible for all contract matters, and the DOE Contracting Officer's Technical Project Officer (TPO) was responsible for technical liaison and monitoring of the project.

The following organizations interacted effectively to meet the intent of the Cooperative Agreement and to assure timely and cost-effective implementation of the MCCTD project from conceptual design through completion of the operation phase.

- New York State Electric & Gas Corporation (NYSEG)
- Saarberg-Hölter-Umwelttechnik (SHU)
- Stebbins Engineering and Manufacturing Company (Stebbins)
- Nalco Fuel Tech
- ABB Air Preheater, Inc.
- DHR Technologies, Inc.
- CONSOL, Inc.

NYSEG had primary responsibility for reporting to and interfacing with DOE and was responsible for all phases of the project.

The overall project approach of the above Participants included the following:

- A single project manager was responsible to the DOE and all project Participants for all three project phases.
- NYSEG was the primary liaison between the Government and all other organizations, as shown in figure 1.2-2, Project Participant Organization.
- The Generation Department of NYSEG's Electric Business Unit managed the MCCTD project. NYSEG's construction management organization was responsible for the overall construction and construction management activities of the project. This included the organization, planning, management, direction, and supervision of all labor and contractor operations. NYSEG was also responsible for material and equipment receipt and inspection, equipment and material storage, temporary construction facilities and services, erection of all equipment and material, and the field activities of the major subcontractors during the construction period. The architect/engineering firm of Parsons Power Group, Inc., formerly Gilbert/Commonwealth (G/C), selected through competitive bidding, supplemented NYSEG administrative, engineering and construction management efforts. NYSEG, with the aid of Parsons, developed the detailed design for the FGD system, as well as for the balance-of-plant systems. The NYSEG-Parsons team developed specifications and procured all equipment components directly from the original equipment manufacturers. They developed the control system design based on operational requirements supplied by SHU. Responsibility for receipt and installation of all components was assigned to qualified specialty contractors. The NYSEG-Parsons team provided construction management for all contract packages. NYSEG normally performs major projects in this manner and has developed organizational procedures to effectively plan, organize, and control the work.

- SHU's main function was to supply process design and operational requirements for the gas treatment, reagent preparation, and solids dewatering systems. SHU also acted in an advisory role to review the detailed design and equipment selection to protect the basic FGD system performance guarantees. They also provided construction and start-up advisory services for the FGD system and training for NYSEG operators.

- Stebbins' main function was to provide the design and construction of the tile-lined FGD absorber.

- NALCO Fuel Tech's main function was to provide the design for the NOxOUT® $NO_X$ abatement technology and to provide start-up support.

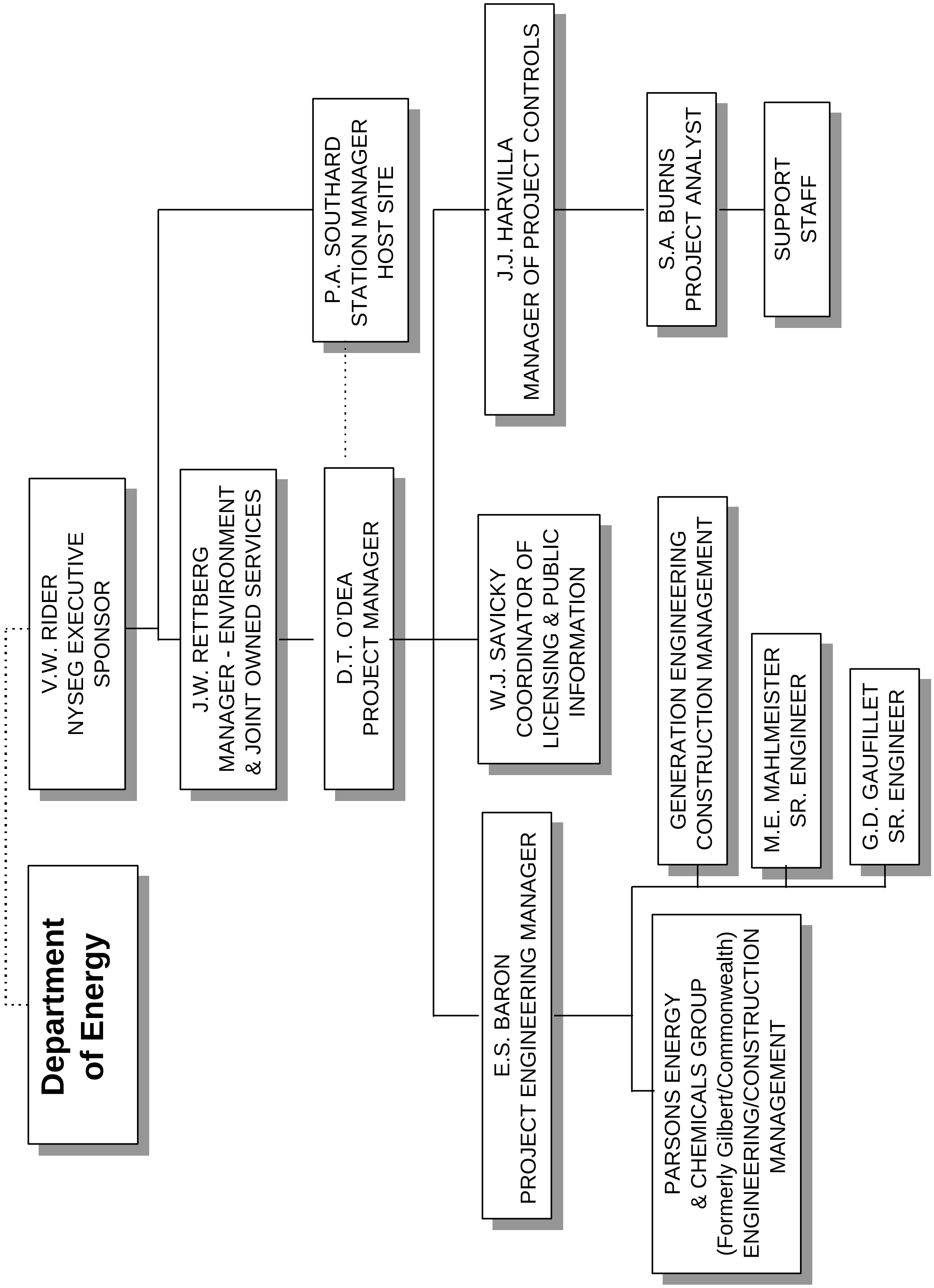
- CONSOL's main function was to assist in the development and implementation of the test plan for the Project.

- ABB Air Pre-Heater, Inc.'s main function was to provide the design and fabrication of the heat pipe air heater.

- DHR Technologies, Inc.'s main function was to provide engineering, design, procurement, inspection, testing, delivery, installation, training and related services in order to provide a Plant Economic Optimization Advisor (PEOA) expert computer system.

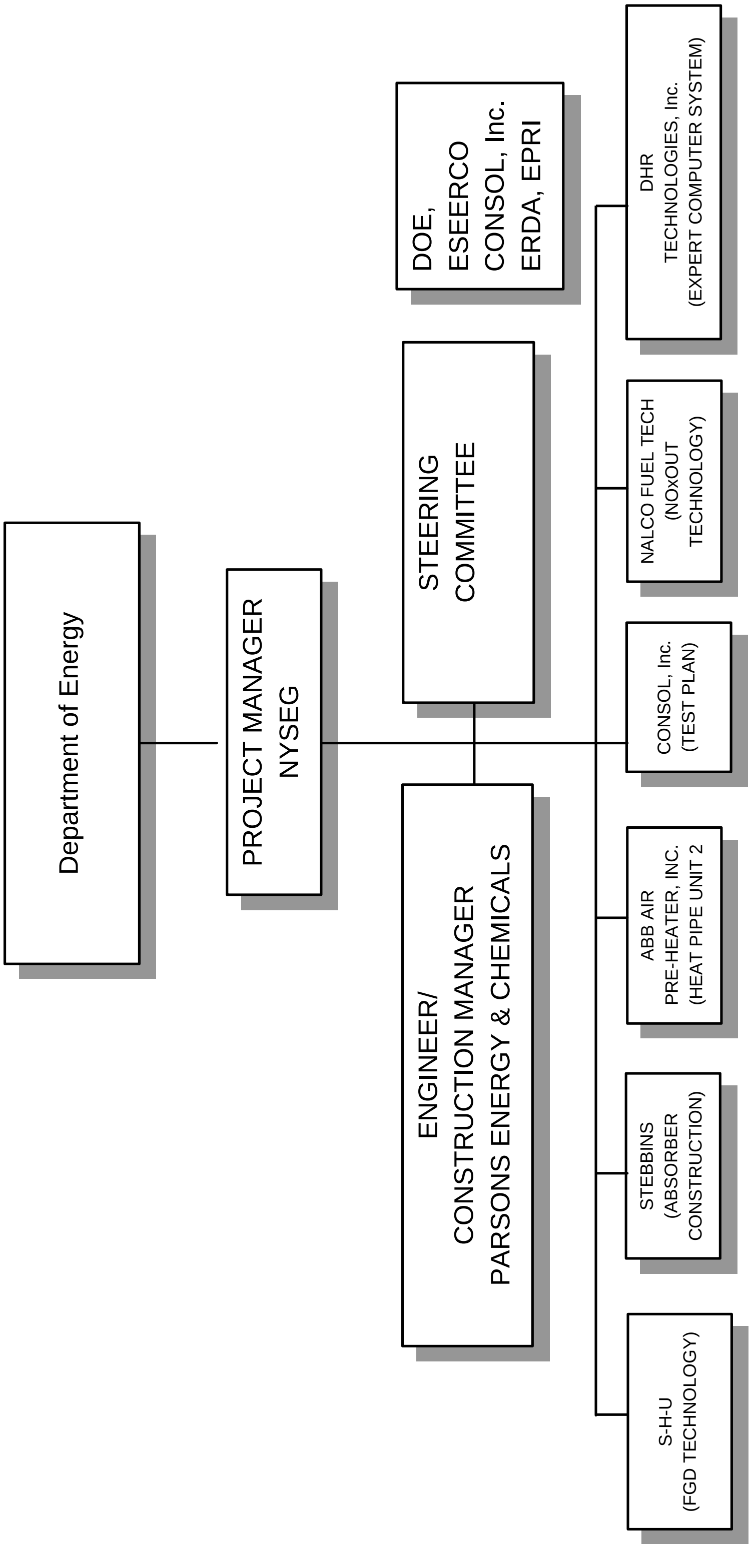
# FIGURE 1.2-1

## NYSEG PROJECT ORGANIZATION FOR MCCTD PROJECT



## FIGURE 1.2-2

## PROJECT PARTICIPANT ORGANIZATION



### 1.2.3 PROJECT DESCRIPTION

The Milliken Clean Coal Technology Demonstration (MCCTD) constructed by the New York State Electric & Gas Corporation (NYSEG) is one of the nine clean coal projects selected for funding in Round IV of the Clean Coal Technology Demonstration Program. This project provided a full-scale demonstration of a combination of innovative emission-reducing technologies and plant upgrades for the control of sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_X$) emissions from a coal-fired steam generator, without a significant loss of efficiency.

| | |
|---|---|
| Project Title: | Milliken Clean Coal Technology Demonstration Project (MCCTD) |
| Proposer and Sponsor: | New York State Electric & Gas Corporation |
| Project Location: | Milliken Station, Tompkins County, Lansing, New York |
| Technology: | A combination of limestone scrubbing, combustion modifications, urea injection, and enhanced heat recovery to reduce $SO_2$ and $NO_X$ emissions while maintaining efficiency. |
| Application: | $SO_2$ and $NO_X$ emissions reductions in pulverized-coal-fired furnaces. |
| Type of Coal Used: | High-sulfur bituminous (Pittsburgh seam) |
| Product: | Pollution Control Technology |
| Project Size: | 300 MWe |
| Project Start Date: | October 20, 1992 |
| Project End Date: | December 31, 1998 |

The purpose of the project was to demonstrate the reduction of $SO_2$ and $NO_X$ emissions without a significant decrease in plant efficiency by installing a combination of innovative technologies and plant upgrades. These included the Saarberg-Hölter Umwelttechnik (SHU) process for $SO_2$ reduction, combustion modifications and the NOxOUT® process for $NO_X$ reduction, and a high efficiency heat pipe air heater system plus other energy-saving modifications to maintain efficiency. This project was the first US demonstration of the SHU process, which included the first demonstration of a tile-lined, split-flow absorber below the flues. This project was also intended to be the first demonstration of the NOxOUT® process in a utility furnace firing high-sulfur coal.

The overall project goals were:

- To achieve 98% $SO_2$ removal from the flue gas, using limestone, while burning high-sulfur coal and maintaining 95% FGD reliability.
- To achieve up to 70% $NO_X$ reduction using the $NO_X$OUT® selective non-catalytic reduction (SNCR) technology in combination with combustion modifications.

- To minimize solid wastes by producing marketable by-products (commercial-grade gypsum, calcium chloride and flyash).
- To achieve zero wastewater discharge.
- To maintain station efficiency by using a high efficiency heat pipe air heater system and a scrubber system with low power requirements.

The Saarberg-Hölter Umwelttechnik (SHU) process was used to reduce $SO_2$ emissions by up to 98%. In the SHU process, the flue gas is scrubbed with a limestone slurry in a cocurrent / countercurrent open spray tower type absorber. The slurry is maintained at a low pH (relative to conventional wet limestone scrubbing processes) by adding formic acid, which acts as a buffer, to the limestone slurry. A slipstream is processed for recovery of high-quality by-product gypsum and calcium chloride. Water is recovered and recycled to the process. This is the first US demonstration of the SHU process and includes the innovative feature of a tile-lined, split-flow absorber constructed below the flues.

$NO_X$ emissions were to be reduced by a combination of combustion modifications and the installation of the NOxOUT® urea injection technology. NOxOUT® technology is capable of reducing $NO_X$ emissions without affecting the salability of the flyash. A high efficiency heat pipe air heater system, provided by ABB Air Pre-Heater, was installed on Unit 2 to maintain station efficiency while $SO_2$ and $NO_X$ emissions are being significantly reduced. The CAPCIS corrosion monitoring system was installed in conjunction with the high efficiency air heater system to control flue gas discharge temperature and prevent corrosion due to acid condensation.

The demonstration project was conducted at NYSEG's Milliken Station, located at Lansing, New York. Milliken Station comprises two 150 MWe pulverized coal-fired units built in the 1950's by Combustion Engineering.

This demonstration was conducted over 69 months. Project activities included design and engineering, construction, start-up, operations, and testing.

### $SO_2$ REMOVAL

The SHU process is the only developed wet limestone flue gas desulfurization (FGD) process which is designed specifically to employ the combined benefits of low pH operation, formic acid enhancement, single loop, cocurrent / countercurrent absorption, and in-situ forced oxidation. The unique cocurrent / countercurrent absorber does not include any packing or grid work. This significantly reduces the potential for plugging and erosion and reduces the energy consumption of the induced draft (ID) fans. The cocurrent / countercurrent design reduces the overall height of the absorber vessel compared to a conventional countercurrent design.

This project was designed to demonstrate the following features of the SHU FGD process:

- up to 98% $SO_2$ removal efficiency with limestone,
- low limestone reagent consumption,

- excellent stability and easy operation during load changes and transients,
- low production of scrubber blowdown,
- freedom from scaling and plugging,
- high availability,
- low maintenance,
- production of wallboard-grade gypsum and commercially usable calcium chloride by-products and
- improved energy efficiency compared with conventional FGD technologies.

This project provided the first demonstration of the SHU process installed directly below the flues. This design approach saves considerable space on site and is advantageous for existing plants where space for retrofitting an FGD process is often at a premium. It also avoids the costs of installing and maintaining ductwork downstream of the absorber.

The SHU FGD process was installed on both Units 1 and 2 with common auxiliary equipment. A single split absorber was used. This innovation featured an absorber vessel divided into two sections to provide a separate absorber module for each unit. This design allows for more flexibility in power plant operations than a single absorber, while saving space and being less costly than two separate absorbers.

An additional feature demonstrated was the use of a tile-lined concrete absorber. The tile lining has superior abrasion and corrosion resistance when compared with rubber and alloy linings and is expected to last the life of the plant. In addition, because the tile-lined concrete construction method requires minimal construction access, it is ideal for use in retrofit projects, where space for construction is often at a premium.

The project demonstrated that, unlike some competing processes that produce gypsum, the SHU by-product gypsum is of excellent and consistent quality, regardless of the plant load level or flue gas sulfur dioxide level.

This project was also the first demonstration of the production and marketing of by-product calcium chloride. The brine concentration system was designed to allow the SHU blowdown stream to be purified and recycled to the plant as FGD make-up water. The calcium chloride produced from the brine concentration system was successfully marketed as a liquid brine solution. However, operating problems with the brine concentrator eventually resulted in its use being discontinued.

## COMBUSTION MODIFICATIONS

Combustion modifications were installed on both Milliken units for primary control of $NO_X$ emissions. These modifications consisted of replacing the existing conventional tangential firing systems with the Low $NO_X$ Concentric Firing Systems (LNCFS) furnished by ABB CE Services. Each system included new burners, wind boxes and over-fire air systems. The LNCFS maximizes the $NO_X$ reduction capabilities of existing tangential firing systems while minimizing unit modification. The LNCFS uses a combination of two techniques to reduce $NO_X$: bulk furnace staging and early controlled coal devolatilization. Bulk furnace staging takes a portion of the combustion air, which is introduced at the fuel burning zone, and diverts it to retard air and fuel mixing. With conventional tangential firing, the introduction of excess combustion air during the early stages of coal devolatilization contributes significantly to the formation of $NO_X$. The LNCFS maximizes the bulk staging concept by using both overfire air and concentric firing. Staged combustion is produced by introducing a portion of the secondary air, called overfire air, above the primary firing zone. This is accomplished with a close-coupled overfire air system, in which the overfire air nozzles are located in the top elevations of the main windboxes, and a new separate overfire air windbox, which is installed above the existing windbox. The concentric firing system re-directs the secondary (auxiliary) air to the main firing zone, diverting it away from the coal stream. In this manner, combustion stoichiometry is reduced by preventing the fuel stream from entraining with the air stream during the initial stages of combustion. Fuel nitrogen conversion is reduced, while maintaining appropriate oxidizing conditions along the furnace walls. The introduction of air in the concentric firing circle is accomplished with the installation of offset air nozzles. Another important design feature incorporated into the LNCFS is the technique of early fuel ignition. Initiating the combustion point very close to the fuel nozzle produces a stable volatile matter flame which is more easily controlled under sub-stoichiometric firing conditions. A two-piece "flame attachment" type coal nozzle tip is used to promote this strong primary flame.

## NOxOUT® TECHNOLOGY

In addition to the LNCFS installed on both Units 1&2 for primary $NO_X$ emissions control, the project planned to install the NOxOUT® selective noncatalytic reduction (SNCR) technology on Unit 2 to provide a further reduction in $NO_X$ emissions. The SNCR portion of the project was eventually relocated to Penelec's Seward Station. The $NO_X$OUT® process achieves $NO_X$ reduction by the reaction of $NO_X$ with urea injected into the post-combustion zones of the boiler.

The installation of the NOxOUT® technology at Milliken would have allowed this project:

- To demonstrate a $NO_X$ emissions reduction of 30% or more over that achieved with combustion modifications alone.
- To demonstrate the cost effectiveness of the NOxOUT® process for $NO_X$ reduction.
- To determine the effect of these $NO_X$ reduction technologies on air heater, electrostatic precipitator (ESP), and scrubber operations and on fly ash quality.

Because Seward Station is not equipped with low $NO_x$ burners the project was not able to achieve the first of these objectives. Also, because Seward Station is not equipped with an FGD system, the project was not able to determine the effects of the NOxOUT® technology on scrubber operations.

## HEAT PIPE AIR HEATER SYSTEM

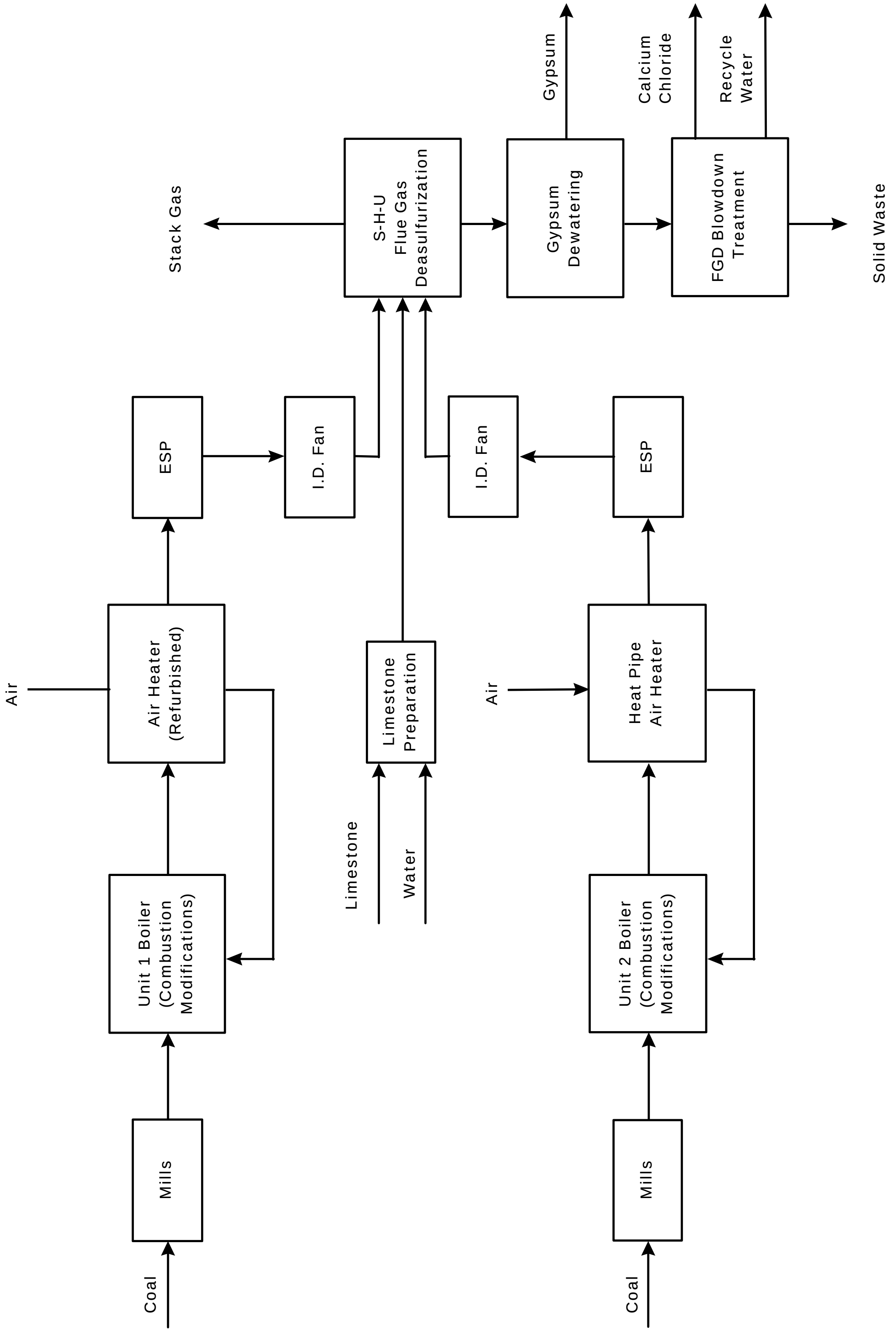
Another component of the project was the addition of a high efficiency heat pipe air heater system, along with other equipment modifications, to maintain the station efficiency, while $SO_2$ and $NO_X$ emissions are significantly reduced. The CAPCIS corrosion monitoring system was installed in conjunction with the high efficiency air heater system to control flue gas discharge temperature and prevent corrosion due to acid condensation. A heat pipe unit uses carefully selected liquids, sealed in tubes, as the heat transfer media. One portion of each tube is in the flue gas stream and the balance of the tube is in the combustion air stream. The liquid in the tube evaporates in the hot (flue gas) portion; then the vapor flows to the cold (combustion air) end, where it condenses. The condensate then flows back to the hot end. The need for special air seals and the associated potential for air heater leakage characteristic of conventional regenerative (Ljungstrom) air heater designs are eliminated with this design, which results in reduced ID fan power consumption. Because of the high efficiency of these units, the temperature of the combustion air is increased, which increases the efficiency of the plant.

## 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. The PEOA system was installed on both of the units at Milliken. 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 PEOA system is designed primarily for plant operators but also provides powerful, cost-saving features for engineers and managers. The PEOA system 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 evaluate key emissions data parameters, including $NO_X$, $SO_2$, $O_2$, CO, $CO_2$, 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 employ the optimization features to evaluate various operation 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.

Figure 1.2-3 presents a block flow diagram of the MCCTD Project.

# FIGURE 1.2-3
# PROCESS BLOCK DIAGRAM FOR MCCTD PROJECT



## DEMONSTRATION TESTING PROGRAM

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

| | |
|---|---|
| 1.03.69.01 | Plant Economic Optimization Advisor (PEOA) |
| 1.03.69.02 | Milliken By-Product Utilization Studies |
| 1.03.69.03 | Training Simulation Models for Boiler $NO_X$ Emission & Control at Milliken |
| 1.03.69.04 | Chemical Emissions Measurement Program at Milliken's Unit #2 |
| 1.03.69.05 | CRT-Based FGD Simulator for Milliken |
| 1.03.69.06 | Validation of Brigham Young University 3D Combustion Code |
| 1.03.69.07 | Milliken Station Environmental Monitoring Program |
| 1.03.69.08 | Stebbins Tile Test Facility |
| 1.03.69.09* | Milliken Evaluation of the Hybrid SNCR/SCR $NO_X$ Control Process |
| 1.03.69.10 | Milliken Selective Non-Catalytic Reduction Demonstration |
| 1.03.69.11* | Milliken-Unit 2 Flame Viewing Camera |
| 1.03.69.12* | Milliken-Unit 2 DUCSYS Risk Assessment |
| 1.03.69.13* | Milliken-Innovative Waste Liners |
| 1.03.69.14 | Milliken-Materials of Construction |
| 1.03.69.15 | Milliken-ESP Upgrade Evaluation |
| 1.03.69.16 | Milliken-SHU Flue Gas Desulfurization Process Evaluation |
| 1.03.69.17 | Milliken-Mist Eliminator (Including Wet Stack) Testing |
| 1.03.69.18 | Milliken-Water Toxics Treatment & Characterization |
| 1.03.69.19 | Milliken-Heat Pipe Air Heater Evaluation |
| 1.03.69.20* | Milliken-Ammonia Analyzer |
| 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 |
| 1.03.69.24 | Milliken-LNCFS 3 Evaluation |
| 1.03.69.25* | Milliken-Establishing Vegetative Buffers on Poor Sites |
| 1.03.69.26 | Milliken CCT IV Test Program Management |

Activities marked with an asterisk were part of the demonstration, but not DOE scope of work.

The scope of each of the DOE funded activities is summarized below.

### Plant Economic Optimization Advisor (PEOA)

This program was designed to demonstrate the capability of the PEOA to integrate with the power plant distributed control system, performance monitoring and information systems on a variety of network topologies, operating systems and hardware platforms.

PEOA is a neural networking system utilizing optimization algorithms for evaluating key emissions data parameters such as $NO_x$, $SO_2$ , $O_2$, CO, $CO_2$, carbon in ash and opacity in addition to other operational parameters such as boiler and turbine operation, gypsum sales, emissions credits and coal quality. The system provides "what if" capabilities to allow users to utilize the optimization features to evaluate various operating scenarios.

### 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 $NO_x$ 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.

### Training Simulation Models for Boiler $NO_x$ Emission and Control at Milliken

The objective of this program was to develop, demonstrate and transfer technology for a simulation model of a coal-fired boiler for use in training operators in emission controls. The emission process and control model provides low cost replica training simulators for use in training plant operators to use emission controls to meet the stringent $NO_X$ environmental regulations. The emission simulation module utilizes a personal computer programmed with detailed process, control and emission models. The simulator provides a tool for control room operators to: study the effect on emissions of the various emission control equipment; develop operating experience, confidence and accuracy in normal and abnormal operation of the emission control equipment; follow specific operating procedures; analyze plant systems, their function and interaction with other systems; learn operation, theory and use of plant controls and practice response and recovery from various malfunctions.

### 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, $Cr^{+6}$, BaP, dioxins and furans) and developing a system mass balance for the metals.

### CRT-Based FGD Simulator for Milliken

The scope of this program included the development and the performance of validation tests of a CRT-based training simulator model for the SHU FGD system.

### Validation of Brigham Young University 3D Combustion Code

The purpose of this program was to evaluate the accuracy of the Advanced Combustion Engineering Center (ACERC) PCGC-3 combustion code to predict key parameters such as $NO_X$ and unburnt carbon in the flyash exiting the boiler. Also included was the development of an empirical model to predict $NO_X$ and unburnt carbon for the Milliken CCTD.

### 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.

### Stebbins Tile Test Facility

The purpose of this program was to document the techniques employed in constructing an absorber module, evaluate crack repair, mortar and tile wear, pipe penetrations and monitor operating and maintenance costs. A video was produced to document construction techniques for installation of scrubber walls.

### Milliken Selective Non-Catalytic Reduction Demonstration

The original purpose of this program was to investigate the capability of additional $NO_X$ reduction utilizing SNCR in conjunction with LNCFS-3. Nalco's NOxOUT® process was to be installed at Milliken 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. The NOxOUT® demonstration was eventually relocated to GPU's Seward Station. Because Seward is not equipped with low $NO_X$ burners, the scope of this project had to be limited to evaluating the performance of the NOxOUT® process without upstream $NO_X$ control.

### Milliken-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.

### Milliken-Materials of Construction

The scope of this program included reviewing 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.

### Milliken-ESP Upgrade Evaluation

The purpose of this 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 $^{o}$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 $NO_X$ control. Also assessed were design aspects of the ESP including power consumption, fields, process optimization of T-R controls and final set points.

### Milliken- SHU 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 process, including associated system components such as the mist eliminator/wet stack and materials of construction. The scope of this program included evaluating absorber module chemistry for limestone grind, formic acid and variations in recycle slurry operation relative to $SO_2$ removal, L/G ratio, pressure drop, formate loss, oxidation air utilization and byproduct gypsum quality.

### Milliken-Mist Eliminator (Including Wet Stack) Testing

The scope of this program included documenting the performance of the full scale mist elimination system including measurements of pressure drop, gas velocity, carryover and droplet size distribution at design conditions and as a function of boiler load and recycle pumps in service. The scope also included documenting the performance of the wet stack including measurements of gas velocity, liquid loading, droplet size distribution and analysis of stack drain composition as a function of boiler load and number of recycle pumps in service.

### 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 were the ultimate disposal and treatment of heavy metal sludge and costs for entire treatment.

### Milliken-Heat Pipe Air Heater Evaluation

This objective of this program was to provide an independent evaluation of heat pipe air heater system for the U.S. utility industry. The scope of the study included evaluation of thermal performance for the as-new condition and thermal performance degradation as a result of fouling and after cleaning. Also included were assessments of corrosion of the heater and of coupons of alternate tube materials. The scope included reviewing the economic benefits of the system including the effects of reduced air in-leakage, lower flue gas temperature, smaller cold side primary air fan requirements, etc.

### 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, $Cr^{+6}$, 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.

### Milliken-LNCFS 3 Evaluation

The objective of this program was to supplement and confirm earlier demonstrations of the LNCFS-3 low $NO_X$ combustion system for tangentially fired boilers. The program scope included 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 included were assessments of the performance achievable with a complete windbox replacement and the use of dynamic classifiers.

### Milliken CCT IV Test Program Management

Aside from its project management and administrative functions the scope of this program included collection and analysis of plant operating data and development of reports addressing operability and reliability and critical component failures.

## 1.2.4 HOST SITE

The MCCTD project is sited at NYSEG's Milliken Station located on the east shore of Cayuga Lake in Lansing, New York, approximately 12 miles northwest of Ithaca. The plant site is at latitude 42°36'30"N and longitude 76°38'15"W. The site is in the Town of Lansing in Tompkins County near the junction of Seneca, Cayuga, and Tompkins counties. The total property area consists of 322 acres. Figure 1.2-4 shows the location of the site relative to major cities in central New York State. The surrounding region is a sparsely populated agricultural area. The bulk of the area's population and industry is concentrated in the cities of Syracuse, Binghamton, Elmira, Auburn, and Ithaca.

There are two coal-fired units, Units 1&2, at Milliken Station. They are Combustion Engineering pulverized coal-fired units which are rated at a nominal 150 MW each and operate under balanced draft mode. Each unit is tangentially fired with four elevations of burners at each of the four corners. Unit 1 was completed in 1955 and Unit 2 was completed in 1958.

Cayuga Lake is approximately 39 miles long in a NNW-to-SSE direction with east-to-west width varying between 1 and 3 miles and a maximum depth of 435 feet. At the site the lake width is approximately 1.75 miles with a normal elevation of approximately 382 feet (msl). In the site region the terrain rises from the lake shore to an elevation of about 800 feet (msl). Within 3 miles east of the site the terrain rises to about 1100 feet (msl). From this region out to 50 miles or more the terrain generally ranges above 1000 feet (msl) with widely scattered high points between 2000 and 3000 feet (msl).

The terrain west of Cayuga Lake is generally similar to that east of the site. Other glaciated valleys similar to that of Cayuga Lake exist west and northeast of the site, forming the other Finger Lakes.

The general climate in the central New York Finger Lakes region is dominated by polar continental air masses tracking from the north and west. Frequent invasions of air masses from the Gulf of Mexico result in rapid variations of weather conditions. The regional climate is characterized by long, cold winters and cool summers with occasional warm, humid periods. Precipitation is evenly distributed throughout the year.

Seismic activity in the region of the site is low. Previous research showed that earthquakes in the northeastern United States are infrequent. The earthquakes that do occur in the northeastern United States are usually of shallow focus and characterized by low magnitude and/or intensity.

Of the type of land on site, the area of construction was mainly grassy with a length of trees surrounding a small, rocky ravine running through the site. The area surrounding the plant up to one mile from the site boundary consists of mostly cropland and lake, with forest and forest brushland making up the next largest classification. This area is sparsely populated with no major population centers.

The site holds several significant advantages to the demonstration. Milliken Units 1 and 2 have, over the years, proven to be two of the most efficient and reliable units in the nation. This proven track record ensured that the demonstration would proceed smoothly according to schedule on units that had to operate to meet load demands. Units 1 and 2 are base loaded units, assuring a good demonstration and providing the opportunity for potential users to observe the technologies in commercial operation. The selection of such an efficient plant underscored the demonstration project team's commitment to achieve high $SO_2$ removal efficiency with minimal FGD energy consumption.

Milliken Station Units 1 and 2 are two comparably sized boilers. This feature was key to the development of this project. It allowed demonstration of the split module absorber concept and, at the same time, permitted independent operation of the SHU process on each boiler unit. Operation of identical absorbers at independently variable conditions allowed process data to be more fully verified and facilitated identification and analysis of abnormalities, either process or physical, as they occurred.

The site holds all the prerequisites to demonstrate this technology, including access, water, rail transport, roadways, electric power, labor force, coal supply and other required utilities as follows:

- Water Supply - Cayuga Lake provides an abundant source of water which is used for all plant needs. The relatively small amount of makeup water required for the FGD system did not require additional water withdrawal from the lake.
- Railroad Access - Railroad access was available on site to meet the requirements for coal deliveries to the station. Rail access was available as required for delivery of equipment and construction materials.
- Electric Power - All power requirements for both the construction and operational phases of the project were easily met from Milliken Station. FGD power is provided by a new substation constructed on the power plant site.
- Labor Force - Construction labor force was available through the Ithaca Building and Construction Trades Council which has as members craftsmen from all required trades, including carpenters, iron workers, laborers, plumbers and electricians. The operating force was readily supplied from current NYSEG employees at the power plant and from the labor force of the surrounding area.
- Coal Supply- Eastern U.S. coal was the major source of supply. The Milliken site accommodates coal delivery via both truck and rail. The majority of coal is delivered by rail.
- Other Utilities - All other utilities such as potable water and sewage treatment were provided by the preexisting power plant resources.

Though Milliken was previously in compliance with all air quality emission standards, changes due to the 1990 Clean Air Act Amendments (CAAA) required more stringent control of air emissions. The installation of the advanced FGD and $NO_x$ control systems with this project ensured that Milliken Station will meet or exceed all current and all newly imposed CAAA $SO_2$ and $NO_x$ requirements.

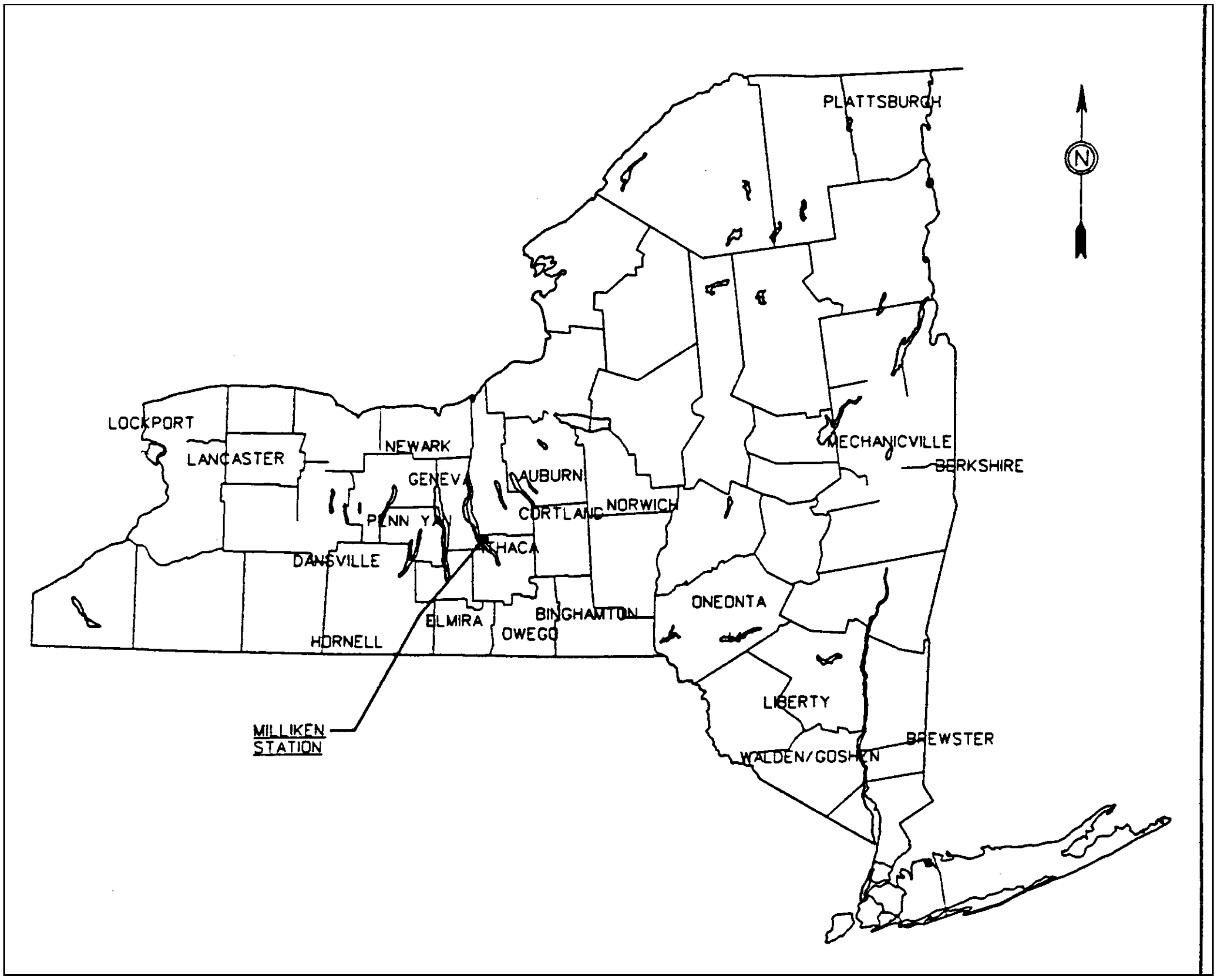
The location of the site in the Finger Lakes region of New York State makes this plant a contributor to acid rain deposition in the Adirondack and the Catskill Mountains. Completion of the project on this site provides environmental benefits to these important natural resources. Due to Milliken's location in New York State, transboundary emissions to Canada are theoretically reduced.

The plant's location in a scenic area raised local concerns about the site's appropriateness for a technology demonstration. However, NYSEG found the surrounding communities as a whole to be supportive of the project due to its many environmental benefits. NYSEG, committed to an active community contact program, began making public contacts prior to project award to inform officials and concerned citizens about plans and address their questions. Initial contacts were favorable and continued throughout the project.

Milliken's proven operating history, its access to water, transportation, road, power, labor and fuel resources, and its proximity to the Adirondack and Catskill Mountains and Canada made it an excellent site for a Clean Coal Demonstration Project.

**FIGURE 1.2-4**

**STATE MAP OF SITE LOCATION**



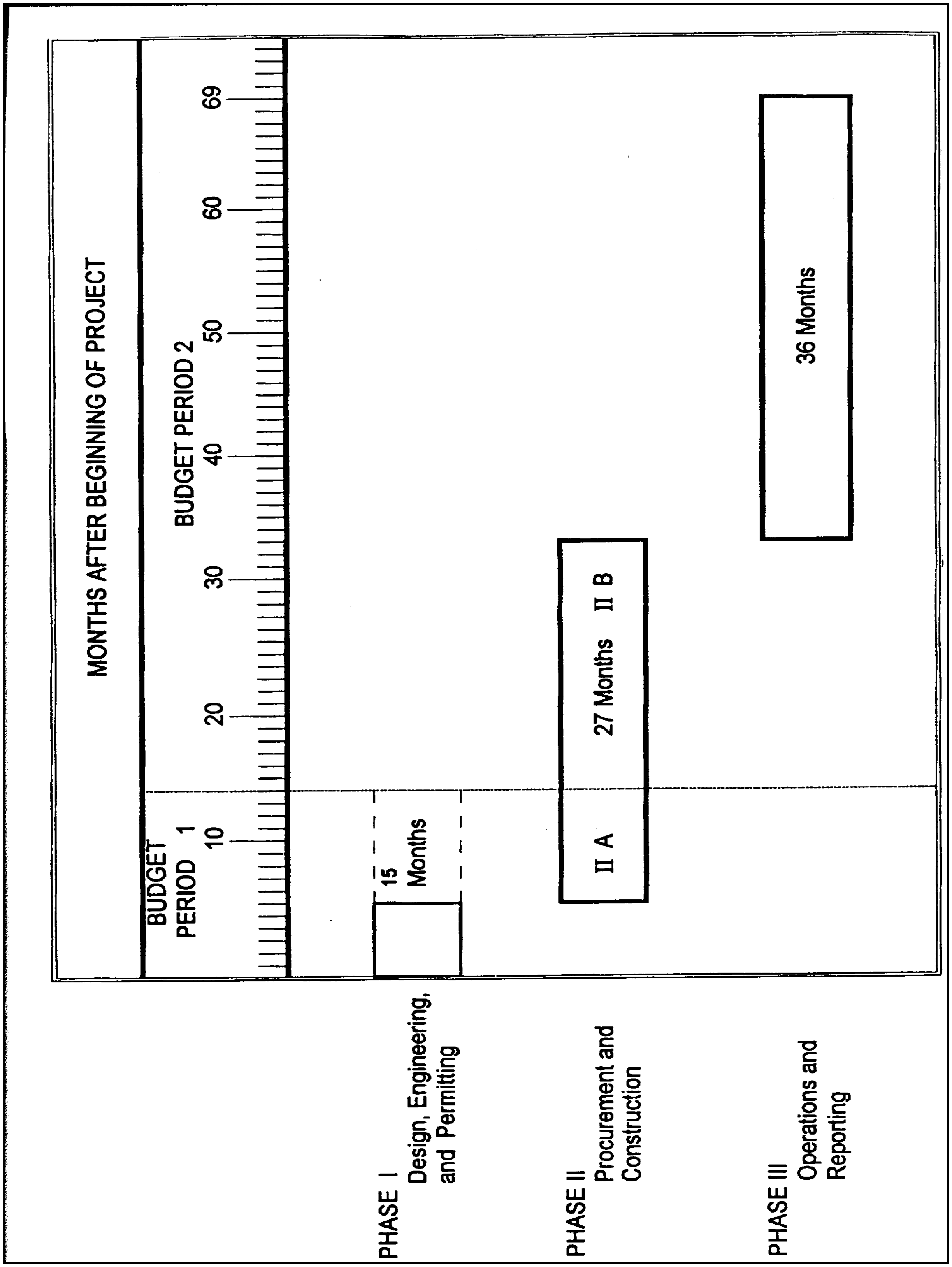
### 1.2.5 PROJECT SCHEDULE

An overview of the project schedule can be seen in figure 1.2-5. The Milliken project was chosen as a successful applicant for partial funding from the Clean Coal Technology IV program in September of 1991. A Cooperative Agreement was executed between NYSEG and the DOE on October 20, 1992. Construction began in April, 1993. Unit 1 electrostatic precipitator upgrade and combustion modifications were placed in operation in September, 1993. Unit 2 electrostatic precipitator upgrade, heat pipe air heater, and combustion modifications were placed in operation in December, 1994. The Unit 2 scrubber module became operational in January, 1995. The Unit 1 scrubber module began scrubbing in June, 1995. The demonstration phase of the MCCTD project officially began in January of 1995 and was completed in December of 1998.

Milestone schedules for each of the three project phases are included in Appendix A.

## FIGURE 1.2-5

## OVERALL SCHEDULE FOR MCCTD PROJECT



## 1.3 OBJECTIVES OF THE PROJECT

The objectives of the project were to demonstrate the reduction of $SO_2$ and $NO_X$ emissions without a significant decrease in plant efficiency by installing a combination of innovative technologies and plant upgrades. These included the Saarberg-Hölter Umwelttechnik (SHU) process for $SO_2$ reduction, combustion modifications and the NOxOUT® process for $NO_X$ reduction, and a high efficiency heat pipe air heater system plus other energy-saving modifications to maintain station efficiency. This project was the first US demonstration of the SHU process, which included the first demonstration of a tile-lined, split-flow absorber below the flues. This project was also the first demonstration of the $NO_X$OUT® process in a utility furnace firing high-sulfur coal.

The overall project goals were:

- To achieve 98% $SO_2$ removal from the flue gas, using limestone, while burning high-sulfur coal and maintaining 95% FGD reliability.
- To achieve up to 70% $NO_X$ reduction using the NOxOUT® selective non-catalytic reduction (SNCR) technology in combination with combustion modifications.
- To minimize solid wastes by producing marketable by-products (commercial-grade gypsum, calcium chloride, and flyash).
- To achieve zero wastewater discharge.
- To maintain station efficiency by using a high efficiency heat pipe air heater system and a scrubber system with low power requirements.

The SHU process is the only developed wet limestone flue gas desulfurization (FGD) process which is designed specifically to employ the combined benefits of low-pH operation; formic acid enhancement; single loop, cocurrent / countercurrent absorption; and in-situ forced oxidation. The unique cocurrent / countercurrent absorber does not include any packing or grid work. This significantly reduces the potential for plugging and erosion and reduces the energy consumption of the induced draft (ID) fans.

This project was designed to demonstrate the following features of the SHU FGD process:

- up to 98% $SO_2$ removal efficiency with limestone
- low limestone reagent consumption
- excellent stability and easy operation during load changes and transients
- low production of scrubber blowdown

- freedom from scaling and plugging
- high availability
- low maintenance
- production of wallboard-grade gypsum and commercially usable calcium chloride by-products
- improved energy efficiency compared with conventional FGD technologies

This project provided the first demonstration of the SHU process installed directly below the flues. This design approach saves considerable space on site and is advantageous for existing plants where space for retrofitting an FGD process is often at a premium. It also avoids the costs of installing and maintaining ductwork downstream of the absorber.

The SHU FGD process was installed on both Units 1 and 2 with common auxiliary equipment. A single split absorber was used. This innovation featured an absorber vessel divided into two sections to provide a separate absorber module for each unit. This design allows for more flexibility in power plant operations than a single absorber, while saving space and being less costly than two separate absorbers.

An additional feature demonstrated was the use of a tile-lined concrete absorber. The tile lining has superior abrasion and corrosion resistance when compared with rubber and alloy linings and is expected to last the life of the plant. In addition, because the tile-lined concrete construction method requires minimal construction access, it is ideal for use in retrofit projects, where space for construction is often at a premium.

The project demonstrated that, unlike some competing processes that produce gypsum, the SHU by-product gypsum is of excellent and consistent quality, regardless of the plant load level or flue gas sulfur dioxide level.

This project was also the first demonstration of the production and marketing of by-product calcium chloride. The brine concentration system was designed to allow the SHU blowdown stream to be purified and recycled to the plant as FGD make-up water. The calcium chloride produced from the brine concentration system was successfully marketed as a liquid brine solution. However, operating problems with the brine concentrator eventually resulted in its use being discontinued.

The project included combustion modifications to both units for primary $NO_X$ emission control. Combustion modifications were an integral part of the project, since they reduce $NO_X$ levels by about 20%. In addition, the $NO_X$OUT® SNCR technology was to be installed on Unit 2 to provide a further reduction in $NO_X$ emissions over that achieved by the combustion modifications alone. The $NO_X$OUT® process achieves $NO_X$ reduction by the reaction of $NO_X$ with urea injected into the post-combustion zones of the boiler.

The installation of the $NO_X$OUT® technology at Milliken would have allowed this project:

- To demonstrate a $NO_X$ emissions reduction of 30% or more over that achieved with combustion modifications alone

- To demonstrate cost effectiveness for $NO_X$ reduction

- To determine the effect of these $NO_X$ reduction technologies on air heater, electrostatic precipitator (ESP), and scrubber operations and on fly ash quality

The SNCR portion of the project was eventually relocated to Penelec's Seward Station. Because Seward Station is not equipped with low $NO_x$ burners the project was not able to achieve the first of these objectives. Also, because Seward Station is not equipped with an FGD system, the project was not able to determine the effects of the NOxOUT® technology on scrubber operations.

Another component of the project was the addition of a high efficiency heat pipe air heater system, along with other equipment modifications, to maintain the station efficiency, while $SO_2$ and $NO_X$ emissions are significantly reduced. The CAPCIS corrosion monitoring system was installed in conjunction with the high efficiency air heater system to control flue gas discharge temperature and prevent acid corrosion due to condensation.

## 1.4 SIGNIFICANCE OF THE PROJECT

Public Law 101-549, the 1990 Clean Air Act Amendment (CAAA), requires many existing coal-burning power plants to reduce sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_X$) emissions. Considering the technology options which are commercially available today, it appears that these existing plants will have to rely heavily on wet flue gas desulfurization (FGD) and $NO_X$ mitigation upgrades to reach the levels of sulfur and $NO_X$ required by legislation.

Flue gas desulfurization is a commercialized technology that has been applied to both new and existing coal-fired utility boilers in the United States since the 1970's. As of February 1989, there were 149 FGD-equipped boilers in commercial service representing 63,289 MW of installed generating capacity and another 18 FGD-equipped boilers, representing 7,726 MW of capacity, planned for future service. The majority of these FGD processes were installed in response to the New Source Performance Standards (NSPS) of December 1971 and June 1979 which mandated $SO_2$ emission limitations of 1.2 lb per million Btu (heat input to the boiler) and a sliding scale of 0.6 to 1.2 lb per million Btu (70 to 90 percent removal), respectively. The remainder of these FGD processes are retrofit applications (38 boilers, amounting to 12,531 MW of capacity) that were installed to meet state or local environmental regulations. As such, the status of FGD technology as applied to the United States utility industry is one directed primarily toward new source applications and FGD retrofit to existing plants in response to the recently passed clean air legislation.

Emissions of nitrogen oxides from coal fired boilers have typically been controlled through combustion modification technology. This technology will not ensure compliance with the mandated reductions. This is evident in the regulatory exception provided in the CAAA for those units where combustion technology fails to meet the emission limits. While the first phase of the CAAA will allow continuation of this practice, stricter guidelines scheduled to be set forth in 1997 will be required to be based on the best available technology taking in to account the costs and energy and environmental impacts. Therefore, control technologies which can demonstrate compliance with emission goals on a cost effective basis will be commercially desired.

### FGD FOR NEW BOILERS

FGD technology development and application has been largely driven by the new boiler market. Consequently, the typical FGD process design philosophy uses small (up to 150 MWe plant size) absorber towers, a spare absorber tower, and liberal sparing of primary and auxiliary components. Moreover, conventional FGD designs require large amounts of space for waste disposal.

### FGD RETROFIT TO EXISTING BOILERS

Retrofit to an existing plant presents problems that are much more difficult than for new plants. Often, the space available for the FGD system is limited, and accessibility for installing the FGD system, maintaining that equipment, or removing old equipment is difficult. Lack of space to retrofit an FGD system at an existing site leads to concerns that include:

- The placement of a number of small absorber towers plus spares becomes difficult or impossible.

- Sparing of primary and auxiliary components becomes difficult.
- Available space for waste disposal is at a premium.
- Accessibility for operation and maintenance becomes difficult.

The net result is a retrofit FGD process that is more expensive, less reliable, difficult to maintain and incapable of performance levels associated with a comparable new system. Generally, this situation becomes more acute for older, smaller existing boilers. All other things being equal, older and smaller plants are more difficult to retrofit than newer and larger plants. This situation occurs because in older boilers, space is usually limited in the beginning. It is further complicated by the fact that older plants are generally modified over time to accommodate new technology. For example, many plants have added or replaced their existing particulate control equipment with additional or new electrostatic precipitators. This reduces the area that might normally be used for an FGD retrofit. This situation is especially acute for existing coal-fired utility boilers in the eastern US where the average age of utility boilers is over 25 years.

## SHU WET FGD PROCESS

The FGD process selected for demonstration for NYSEG's Milliken Station is the Saarberg-Hölter Umwelttechnik GmbH (SHU) wet limestone process which was developed in Germany, where one of SHU's parent companies is an electric utility.

The SHU process is unique among wet limestone processes in that it was designed to take advantage of the benefits available from low pH operation by adding small amounts of formic acid to the recycle slurry. The formic acid improves the $SO_2$ removal efficiency of the wet limestone process, eliminates scaling and plugging, and acts as a buffer to control the pH drop of the recycle slurry. Other suppliers have at times attempted to use an organic acid to improve the performance of their FGD system processes which did not in some way meet performance requirements. However, no other supplier except SHU offers a system designed at the onset to take full advantage of the many inherent benefits of formic acid buffering. Unless an FGD system is initially designed to use an organic acid, many of the benefits of buffering are lost. The system will not be properly configured to take full advantage of low pH absorption unless specifically designed for it.

### SHU Process Development

Saarberg-Hölter Umwelttechnik GmbH was formed in Germany in the mid-1970's as a joint venture between Saarbergwerke AG, an electric utility, and Hölter GmbH, an engineering company, and was assigned the task of developing an FGD process that would have high $SO_2$ removal efficiency, high reliability, and low maintenance, while producing a marketable by-product.

Laboratory-scale experiments indicated that organic acids enhanced $SO_2$ removal in calcium-based FGD systems. A 40 MW demonstration plant was installed at Saarberg's Weiher II power station, followed by a 175 MW commercial unit at the Weiher III station in 1979. These installations were designed to use a lime slurry, buffered with formic acid addition, as the reagent for $SO_2$ absorption. The absorbers were of high-velocity, cocurrent, venturi-throat design with 85% removal efficiencies. A separate oxidizer tank for sulfite oxidation and a thickener for primary dewatering were installed. Although these plants were successful in operation, the operating costs were high due to the high pressure drop across the absorber and high lime prices.

In 1982, a second unit at Weiher III was commissioned utilizing a cocurrent type absorber and limestone as the reagent, and 90% $SO_2$ removal efficiency was achieved. As a result of the experience gained from the first unit at Weiher III, the oxidation step was integrated into the absorber sump, and the thickener was eliminated. A similar design was installed at the Saarberg Bexbach station. More stringent acid rain legislation was passed in Germany in 1982. To meet the new limits, all subsequent SHU installations utilized a combination cocurrent / countercurrent absorber designed to achieve 95% $SO_2$ removal efficiency tracking 200 mg $SO_2/m^3$ or 70 ppm. The highest sulfur dioxide inlet concentration demonstrated in a commercial unit is 2.5% sulfur (bituminous coal equivalent) at the RWE Neurath lignite station. The system has been demonstrated on single modules of 125 to 550 MW, firing low-sulfur bituminous coal, oil and lignite fuels. The system has also been demonstrated successfully on two 20 MW stations in Turkey burning 8% sulfur lignite. Overall there have been approximately 30 installations of the SHU FGD process in Europe and Asia, serving over 8,000 MWe of plant capacity. Based on the greater than 98% reliability experienced on previous SHU units the last two FGD units at Saarberg, which discharge the treated gas to the cooling tower, were purchased without a stack for bypass.

## Significant Features of the SHU Process Demonstration

The key features of the SHU FGD technology which contribute to its marketability are competitive capital and operating costs, consistently high $SO_2$ removal (95-98%) over wide load ranges; efficient limestone utilization; ease of operation during plant transients; consistently high quality gypsum by-product; low energy requirements; excellent reliability and low maintenance cost. The process's formic acid buffering permits operations within a pH range that precludes the formation of sulfite scale, often a problem in competing wet FGD systems. The buffering also has another significant advantage in that it permits high $SO_2$ removals at lower liquid to gas ratios. SHU absorbers may be used effectively on a wide range of boiler sizes. The SHU process is also particularly well suited for the treatment of flue gas from burning high-chloride coals, because of the buffering effect of the formic acid additive. No prescrubber is required, and the process can operate with more than 50,000 ppm chloride in the recycle slurry without a detrimental effect on performance. Chlorides absorbed from the flue gas exit the system as calcium chloride dissolved in the scrubber blowdown stream. The calcium chloride can be recovered and sold as a by-product for road deicing, used as a desiccant, etc.

The ability to produce commercial grade gypsum, calcium chloride and other potentially useable material will be a key economic element in the total evaluated cost for some systems. Successful demonstration of this feature will add to the SHU process flexibility and cost advantage, thereby enhancing its commercial viability. The demonstration is consistent with the goals of environmental regulators in reducing landfilled waste.

SHU's European and Asian installations have shown that the process is capable of high $SO_2$ removal efficiency, high reliability, low maintenance, high energy efficiency and high limestone utilization, at competitive capital cost while producing salable byproducts and a reduced FGD blowdown stream when compared to other commercially available FGD systems. The MCCTD project was designed to demonstrate that these superior capabilities are achievable while treating flue gas from boilers fired with about 1.7 to 4.2 % sulfur US sub-bituminous coals, which are typical fuels utilized in Eastern US coal-fired utility boilers, with equipment available in the United States, and when the FGD system is operated and maintained in accordance with normal US utility practices.

An important project goal was to demonstrate that the reliability achieved by the SHU process in Europe can be achieved with US coals, US designed and manufactured components and US operating and maintenance practices. If this reliability can be demonstrated, then the cost savings of constructing an FGD system without a spare absorber module can be made available to US utilities.

The SHU design includes a below-stack absorber, a feature which should greatly enhance the acceptance of SHU technology as a retrofit option to a large number of existing plants with similar space restrictions as Milliken Station. FGD processes, such as SHU, which offer below-stack designs will fit at existing sites where another type of FGD system would otherwise have to find expansion room that often is unavailable. Construction costs at constricted sites are higher. There are design compromises and construction is difficult. Therefore, site-specific retrofit FGD cost should be lower for below-stack designs compared to designs which do not allow below-stack absorbers.

The concept of constructing an absorber module below the flues has not been previously demonstrated in the US, although this concept has been demonstrated at the 220 MW coal-fired Mellach Generating Station, located near the City of Grax in southeast Austria. The plant, which supplies electricity and district heating to the city and the neighboring region, burns a variety of coals procured in the international coal market with sulfur contents ranging from 0.3% to 2.0%. The plant is equipped with a single absorber module (no spare). The FGD process uses wet limestone in an open countercurrent spray tower and produces commercial-grade gypsum. The scrubbed flue gas is reheated. The cylindrical spray tower and its accessories, including the slurry recycle pumps, are located inside the enlarged base of the stack. The stack has a single acid resistant brick and mortar flue to handle both cleaned and raw (bypass) gas. The plant went into commercial operation in 1986 and has since operated satisfactorily, meeting or exceeding $SO_2$ removal efficiency and system reliability guarantees.

The Milliken demonstration project differs from the Austrian unit in several significant areas. The MCCTD project uses multiple stack flues vs. a single flue for the Mellach Plant. The multiple flue design presents a more complex structural problem, especially with respect to supporting the flues above the absorber module. Mellach has a circular absorber base, the Milliken demonstration is rectangular. The Milliken design utilizes a wet stack whereas the Mellach Plant has reheat. Successful operation without reheat would provide further evidence that expensive reheat can be eliminated. The reference plants operate with low sulfur coal whereas the demonstration was designed to use coals with up to 3.2 percent sulfur coal and to test coals up to 4.0 % sulfur coal. Higher sulfur content generally requires higher liquid-to-gas ratio for a given $SO_2$ removal efficiency which imposes a greater load on the absorber's mist eliminator. Mist eliminator performance at these higher loadings is key to avoiding carryover of slurry and potential solids buildup in the stack flue.

If significant amounts of solids were to accumulate on the inner surfaces of the stack flue, agglomerated deposits may break off, falling back into the absorber module, possibly causing damage to its internals. This degree of buildup will be a function of process chemistry, process design and mist eliminator performance. Excessive solids buildup on the flue liner should appear, if at all, during the demonstration run. The programs of inspections during the demonstration period were designed to alleviate this concern.

Finally, the total capacity of the demonstration plant is 300 MW as compared to 220 MW for the Mellach Plant. This difference translates to a larger stack diameter and a somewhat more complex structural design which has been successfully implemented at Milliken.

Successful transfer of an overseas technology to the United States involves the division of responsibility between the technology's overseas developer and the architect/engineer responsible for detailed design and procurement. The overseas company must be sufficiently involved in the project's design to ensure that the design details essential to system performance are properly addressed. The domestic architect/engineer must have sufficient knowledge of the basic process design to ensure the proper selection of US manufactured components and the proper application of US codes and standards. The design approach outlined in Section II.F.1.2 of the Demonstration Project Proposal was intended to address these interface issues. Although the SHU process has been demonstrated using the technology and equipment available in Europe, this demonstration will only use equipment available in the US.

The demonstration tested all aspects of the technology at commercial scale on a commercial coal-fired unit. Data collection, analysis and reporting performed during the operations phase included on-stream factors, material balances, equipment performance, efficiencies and $SO_2$ emission levels. The data generated are directly applicable to other applications and provide valuable information to permit commercialization.

### Performance of the SHU Process

Successful demonstration of high $SO_2$ removal efficiency (up to 98%) will provide the utility industry a process that is capable of providing flexibility. The 1990 CAAA establish utility wide emission allowances. The individual utility has flexibility in reducing $SO_2$ emissions from individual boilers and in earning $SO_2$ emission credits which can be marketed. The SHU process, with up to 98% $SO_2$ removal capability, provides the utility with greater flexibility in developing compliance plans.

The parametric testing program described in Section 4.8 was designed to quantify the performance of the FGD process under varying conditions of coal sulfur content, formic acid concentration, scrubber L/G ratio, flue gas velocity and limestone grind size while operating at high chloride concentration (approximately 40,000 ppm) and 1.02 limestone utilization ratio. The results reported in Section 4.8 verify the process's capability for high $SO_2$ removal efficiency with high energy efficiency and high limestone utilization, even in the presence of high chloride concentrations. The testing program included sampling and analysis which confirmed the consistently high-quality of the gypsum by-product and the marketability of the calcium chloride brine produced.

### Operability and Reliability of the SHU Process

The SHU process reliability reported during commercial operation in Europe exceeds

95%. The SHU FGD demonstration project reliability results at Milliken will be reported to the DOE and included in marketing materials produced and published by SHU. A three year demonstration should be adequate to assess the goal of 95% reliability without spare modules on high sulfur coal as well as to assess the reliability of many of the individual components.

Milliken station has a minimum 20 year remaining life. There will be continuing feedback after the demonstration run on maintenance costs and reliability for individual components as well as total plant.

Section 4.8 also discusses the operating history of the SHU process demonstration with emphasis on ease of operation, frequency of process upsets and ease of recovery from such upsets. Specific problems encountered are discussed together with the solutions developed to eliminate them. The process's performance stability and load following performance are described. Critical component failures are described and analyzed. System reliability and availability are quantified. The observations made during periodic inspections are summarized with emphasis on the degree of solids accumulation in the ductwork, absorber and stack flues, which are critical to the viability of the below stack design concept. The data presented confirm high reliability, low maintenance and ease of operation during plant transients that are characteristic of the SHU process.

### Economics of the SHU Process

The successful demonstration of removal efficiency, low energy consumption with high availability without spare modules, based on SHU organic acid buffered, limestone reagent, low pH chemistry would realize the potential for substantial capital and maintenance cost savings over the present FGD designs.

Section 6 presents the estimated capital and operating and maintenance costs for the SHU process that were derived from the data collected during the demonstration. The results confirm the competitiveness of the process when compared to other commercially available FGD systems.

### STEBBINS REINFORCED CONCRETE, SEMPLATE™ CERAMIC TILE ABSORBER

The FGD absorber for Milliken Station is constructed of the Stebbins Reinforced Concrete / Ceramic Tile system. Stebbins ceramic tile is abrasion, corrosion, and thermal shock resistant. It is durable and provides exceptional strength. The tile system is amenable to a broad range of FGD chemical environments and is not limited to the SHU process. Ceramic tile is corrosion resistant throughout the entire range of FGD operating conditions (temperature, pH, chloride concentration, and organic acid additives).The Stebbins construction can be implemented as a separate structure for new or retrofit installations or implemented as here as an below-stack absorber to save space. It can also be implemented as a single module or as a split module absorber as at Milliken. 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.

Reinforced concrete vessels lined with Stebbins' proprietary SEMPLATE™ ceramic tile are commonly used in corrosive services in the pulp and paper, chemical, and mining industries, but application of this technology to FGD absorbers has been limited. This method of construction was developed in the early 1930's by Stebbins. Since then, they have constructed thousands of vessels. During the last few years, Stebbins has completed many projects in the power industry, including both retrofit linings and new construction. Stebbins successfully designed and installed four M.W. Kellogg horizontal-weir type scrubbers of reinforced concrete, SEMPLATE™ ceramic tile construction at Big Rivers Electric's D.B. Wilson generating Station in Centertown, KY. The first three modules were completed in 1982, and the fourth was installed in 1986.

The MCCTD project differs in several respects. The M.W. Kellogg design is for horizontal gas flow whereas the Milliken absorbers have vertical, cocurrent/ countercurrent, gas flow. Therefore, the Milliken absorbers are much taller. D.B. Wilson Station has three operating modules with one spare, while Milliken has a single split module absorber (forming two operationally independent halves, one for each unit) with no spare. The reliability demand for Milliken Station is much greater. The SHU process operates at a lower pH, formic acid enhanced, higher chloride environment than the M.W. Kellogg process. The Milliken project demonstrates the applicability of Stebbins' ceramic SEMPLATE™ tile construction to a more corrosive environment. The SHU process has traditionally employed rubber-lined carbon steel as the absorber material.

A goal of the MCCTD project is to demonstrate the superior abrasion and corrosion resistance of the Stebbins design compared to more conventional alloy and elastomer or flakeglass lined steel absorbers. This superiority will be of even greater significance as ever tightening liquid discharge limits require FGD systems to operate with zero liquid discharge, forcing high chloride concentrations in the recirculating slurry. Demonstration of the Stebbins tile construction in conjunction with the SHU FGD process design further enhances the acceptance of Stebbins technology as a retrofit option and as a new plant option. The SHU process operates at lower pH and at higher chloride concentrations than other wet lime/limestone processes, and 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 should enhance its acceptance as a construction option.

Corrosion of the absorber module is a problem that has plagued the FGD industry since the earliest installations. A great variety of solutions to this problem have been tried over the years. One class of solutions has involved the application of various coatings or linings over a carbon steel substrate. The success of this class of solutions has been influenced by many factors including suitability of the coating material for the application, adequacy and quality control of installation methods, proper substrate preparation, etc. It is widely recognized that regardless of the care taken in the selection and installation of the lining system, extensive repair or replacement will be necessary sometime during the life of the plant.

The second major class of solutions to the corrosion problem has been to use corrosion resistant alloys in the construction of the absorber module. In cases where the proper alloy has been specified this solution has provided corrosion protection for the life of the plant. However, for severe applications the required grade of alloy can be prohibitively expensive. Recent designs have utilized a thin sheet of alloy material spot-welded to a carbon steel substrate to reduce the cost of the alloy design.

Conventional lined carbon steel and alloy absorber constructions require that the absorber module be shutdown in order to repair leaks in the absorber walls. Repair of absorber module coatings and linings, when applied over carbon steel substrate, requires that the absorber module be shut down for significant periods of time. A valuable asset of the Stebbins tile construction is that leaks in exterior walls can be repaired from outside the absorber vessel, with the absorber in operation. Successful demonstration of this advantage of the Stebbins tile system further enhances absorber availability and further reduces the need for a spare absorber module, saving plot space and capital cost, important considerations for a utility company selecting an absorber construction.

The units at Milliken Station have high capacity factors, 85%. Both units are included to demonstrate the reliability of the Stebbins tile, split module concept. A key aspect of this concept is that internal inspection and maintenance can be performed in one half of the module while the other half is in operation. In order to show that all necessary maintenance activity can be performed during scheduled boiler outages (and not affect generating unit availability) each module section was sized to handle the flue gas from one boiler, thus ensuring that the flue gas from at least one unit could always be processed. A measure of the success of the demonstration is whether all necessary maintenance can be performed without bypassing or without forcing shutdown of one or both boilers.

A major risk associated with employing the Stebbins' tile reinforced concrete design concerned potential corrosion of the concrete and rebar, due to leakage through cracks in the tiles or deteriorated mortar. To repair leaks, Stebbins devised a repair method based on visual detection of a leak, drilling a hole from outside of the vessel, and pumping sealant through the hole to seal the leak. Since repairs to the external walls may be safely made while the unit is in operation, unscheduled shutdown for leaks should not be required. In addition, inspection and repointing, if necessary, of the mortar between the tiles is be performed during scheduled boiler outages.

Because of its resistance to chemical attack and its ease of repair, the reliability of the tile and mortar system is expected to be superior to any other material for absorber construction, and life cycle costs are expected to be substantially lower than those of either a steel alloy absorber or a carbon steel absorber lined with chlorobutyl rubber or flake glass. 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. The demonstration of a corrosion resistant design lasting the life of the plant at significant cost savings when compared to alloy construction should be a significant benefit to the utility industry.

Many of the older coal-fired boilers that are potential candidates for retrofit FGD systems have very limited plot space available for the installation of scrubbers. The construction of an absorber in the base of the stack has often been proposed as one solution to this problem. However, concerns exist in the utility industry with the practicality of this approach. Practical issues primarily concern design interface details between the scrubber and the stack, such as how the stack flue will be supported, and constructibility issues such as the construction of the absorber module in tight quarters. Because the Stebbins tile, split module absorber design consists of a below-stack absorber this demonstration project will greatly enhance the acceptance of Stebbins technology as a retrofit option to a large number of existing plants with limited site space. Absorber construction systems such as Stebbins tile which offer below-stack designs will fit at existing sites where another type of construction would otherwise have to find expansion room that is often unavailable.

Site-specific retrofit FGD cost is lower for below-stack designs than for those designs which do not allow below-stack absorbers.

Many of the utility boilers that are potential candidates for the installation of FGD systems are extremely limited with respect to constructibility access. Construction costs at constricted sites are higher and therefore there are design compromises and construction is difficult. The constricted site advantages of Stebbins tile construction are not limited to below-stack designs. Limited construction access is necessary to implement the reinforced concrete/tile lined system. This asset enables a utility company to retrofit a Stebbins absorber between existing structures without having to provide space for cranes to lift large sections of steel or alloy absorber shell.

The MCCTD project utilizes the unique concept of a split module absorber design. The Milliken FGD absorber is a concrete vessel with tile lining that has a common center dividing wall to provide each unit with its own absorber module. Since each side of the vessel operates independently of the other, this split module design allows the flue gas from each boiler to be independently treated at a lower capital cost than would be required for the construction of two separate vessels. The split module design concept also provides the plant with greater operating flexibility and reliability than a single large module while, at the same time, it saves valuable plot area compared to two separate modules.

The split module design concept would be applicable to power stations with multiple boilers and high capacity factors. Each module section, 150 MW, is applicable to a significant proportion of the older coal-fired boilers impacted by the recent Clean Air Act Amendments. Design details developed and demonstrated during the demonstration project are directly transferable to these units. The project size is such that these details can be easily scaled to suit boiler units from 100 MW to 320 MW, per module section. The split module design can also be utilized as two 50% capacity modules. Design details are therefore be directly applicable for boilers of 320 MW and easily scalable to 640 MW.

The integration of two FGD modules in a single vessel has not previously been demonstrated commercially. The primary risk associated with a split module design, as compared with two independent modules, concerns the integrity of the central wall that divides the module into independent halves and thermal expansion problems that could result from a high temperature gradient across this wall. With the split module design, there will always be flue gas flowing on one or both sides of the central wall. Repairs to this wall, such as sealing leaks and repointing, are performed while there is hot gas on the opposite side. Important goals of the project are demonstrating the success of the repair method and proving the reliability of the split module design and the ability of the central wall to act successfully as a barrier between a hot operating module and a cool off-line module.

A major cause of the premature failure of absorber module coatings and linings has been high temperature excursions. Such excursions may occur as a result of air heater failure causing the temperature of the inlet flue gas to rise to approximately 700 $^{o}$F from its normal value of less than 300 $^{o}$F. Loss of power to the absorber recycle slurry pumps and/or quench spray pumps can prevent the proper quenching of the inlet gas, exposing the absorber lining to higher than design gas temperatures. Either of these conditions can severely impact liner life and can, if severe enough, cause catastrophic liner failure. The Stebbins SEMPLATE ceramic tile provides natural resistance to these temperature excursions, effectively eliminating this mode of liner failure, 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 most marketable aspect of the tile itself should be its expected lower life cycle costs compared with other construction materials. The life cycle costs associated with the use of a tile and mortar lining system are expected to be substantially lower than those of either steel alloy or rubber liners. The combination of durability and reliability will enable Stebbins to effectively market this product to FGD vendors and utilities.

### Operability and Reliability of the Stebbins Absorber

The operating history of the Stebbins Absorber will be the subject of a future topical report. The report will include observations made during periodic inspections with emphasis on the degree of corrosion, abrasion and cracking of the tile and mortar system. The report will summarize maintenance records collected during the demonstration run and document types and costs of maintenance, the impact on availability and boiler operational status during the maintenance activity. All incidences of leakage, repairs and repointing will be reported. Critical component failures will be described and analyzed. The data presented should confirm the high reliability and low maintenance characteristic of the Stebbins construction.

### Economics of the Stebbins Absorber

Section 6 presents the estimated capital and operating and maintenance costs for the Stebbins Absorber that were derived from the data collected during the demonstration. The results confirm the competitiveness of the construction method when compared to other commercially available designs. These data could be used by utility companies in their economic evaluation of this design option.

## HEAT PIPE AIR HEATER SYSTEM

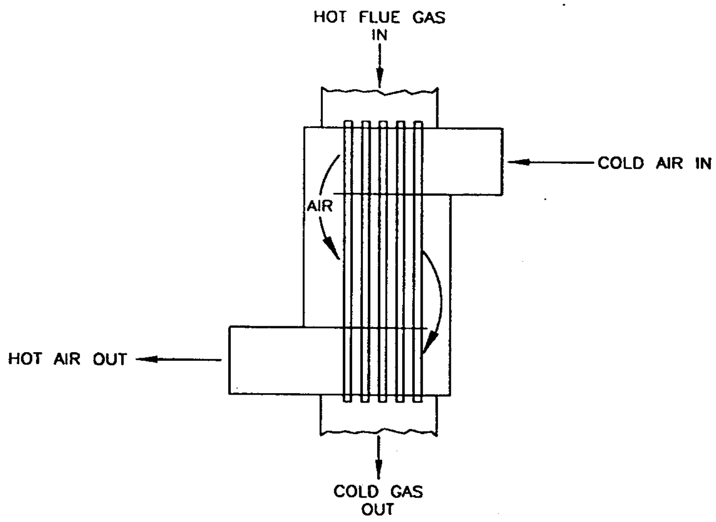
The MCCTD project includes replacement of the Unit 2 Ljungstrom® type air heaters with ABB Air Preheater heat pipe type air heaters. The heat pipe, an innovative replacement option for conventional air heaters, offers energy savings by eliminating air leakage across the air heater and by allowing lower average exit gas temperatures (to maximize air heater energy recovery) by maintaining a uniform gas temperature profile. The application of this technology at Milliken also intended to use the CAPCIS corrosion monitoring system in conjunction with air heater air bypass control to minimize flue gas temperature while preventing corrosion of downstream components.

### Use of Air Heaters In Utility Boilers

The hot flue gases from coal-fired electric utility boilers contain significant amounts of thermal energy. At 650$^0$F, the <u>sensible</u> heat of the flue gas leaving a boiler economizer is typically about 15 percent of the fuel energy. Common practice is to recover most of this energy by preheating the combustion air in recuperative or regenerative heat exchangers.

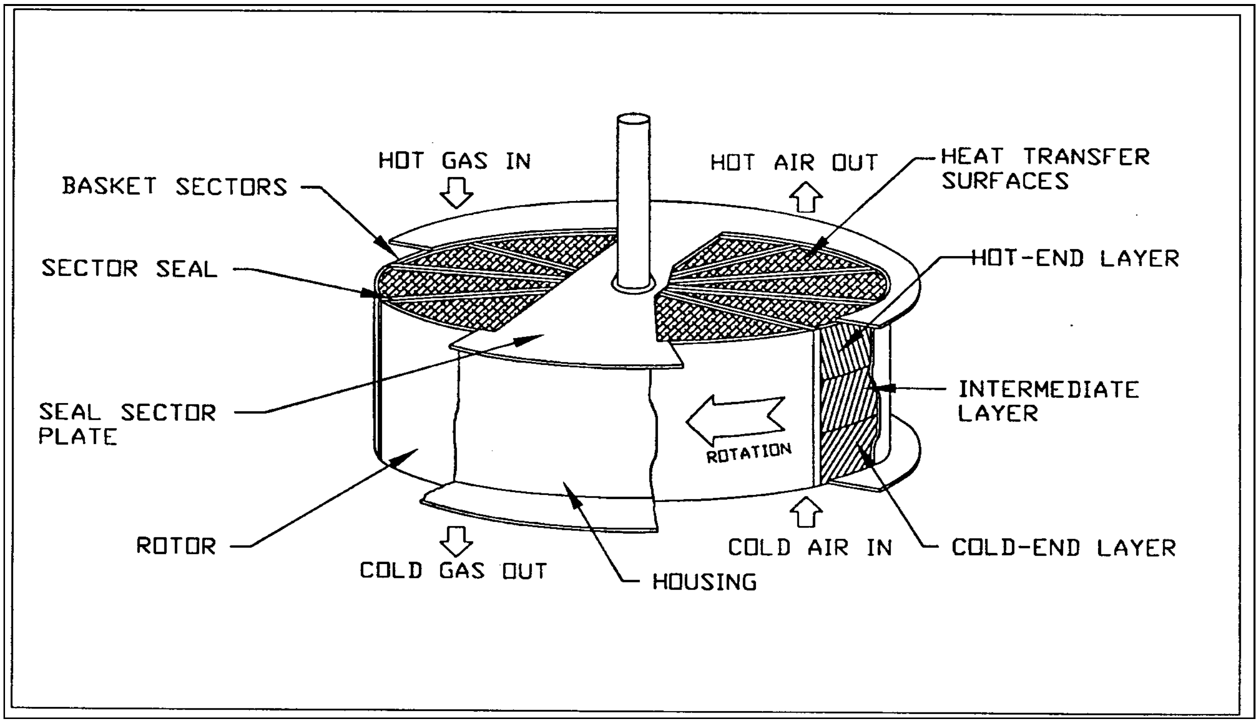
In a recuperative heat exchanger, the flue gas and air streams are separated by the heat transfer surface. Heat energy from the flue gas is transferred directly across the heat transfer surface to the air. Tubular air heaters (figure 1.4-1) in which the hot flue gases pass through metal tubes with air passing around the outside of the tubes are the most common type of recuperative heat exchanger used. These units provide a passive operating design with no moving parts and, when new, can have a low or zero leakage between the air and flue gas sides. The units are, however, physically large as compared to other types of air heaters and are prone to cold-end corrosion and fouling if tube wall temperatures drop below the acid dew point of the flue gas. With time, air leakage increases as more and more tubes corrode through. With acid condensation, serious fouling can occur due to the formation of sticky fly ash/acid poultices. Poultice formation can plug tubes. For the open tubes, this increases outlet temperatures and flue gas side pressure drops.

**FIGURE 1.4-1**
**TUBULAR RECUPERATIVE AIR HEATER, THREE AIR PASS - COUNTER FLOW UNIT**



The rotating wheel (rotor) Ljungstrom® type exchanger is the most common type of regenerative air heater used by utilities. In these units, heat is transferred indirectly from the hot flue gases to the cooler combustion air through an intermediate medium; in this case, a basketed rotor containing many corrugated metal plates (figure 1.4-2). The corrugations separate the plates and provide a torturous path for gas or air to flow to improve the heat transfer. The rotator continuously turns through the flue gas and air streams. The metal plates in the rotor baskets absorb sensible heat from the flue gas as the rotor turns through the flue gas side of the exchanger. This heat is transferred to the air as the hot plates rotate through the air side. The design is compact and provides efficient heat transfer.

**FIGURE 1.4-2**
**ROTATING BASKET (LJUNGSTROM® TYPE) REGENERATIVE AIR HEATER**

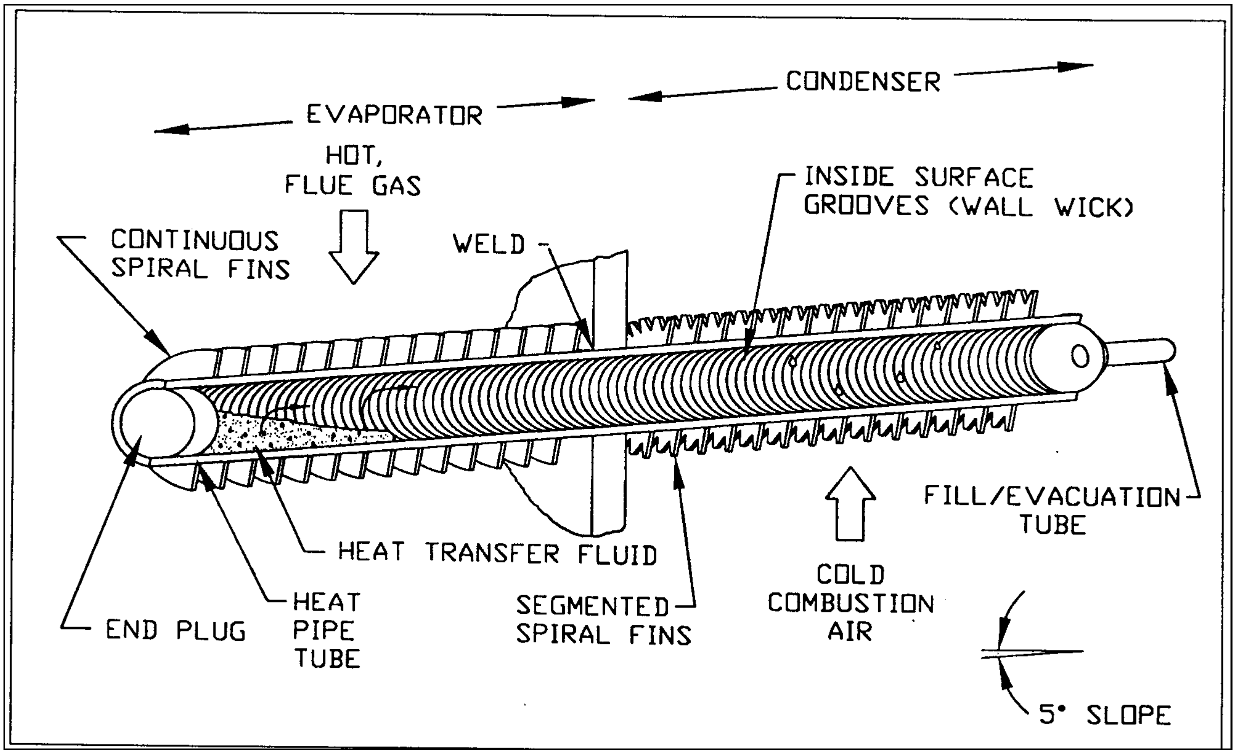


Although there are seals around the rotor, leakage from the combustion air side of the exchanger into the flue gas side is perhaps the biggest problem with the design. The leakage occurs in three areas, across the radial seals, in the clearance between the rotor and the metal case, and by entrainment from the basket gas passages as the baskets rotate from the air side into the flue gas side. When new, the air leakage may be as low as 5% of the incoming flue gas flow. As the seals wear, this can increase to 15-25% or higher. The air leakage increases the forced draft fan power consumption since the leaked air by-passes the combustion step and more combustion air must be supplied. The induced draft fan power also increases since the flue gas flow out of the air heater increases by the amount of air leakage. Additionally, the air leakage reduces plant thermal efficiency since less heat is transferred to the combustion air, and increases maintenance on the air heater due to the need to replace or adjust worn seals.

### Description of the Heat Pipe Air Heater Concept

The heat pipe is a new heat exchanger design which can be used for utility air heaters. The heat pipe design has the potential to eliminate many of the problems associated with the tubular and Ljungstrom® air heater designs and to operate at somewhat lower flue gas outlet temperatures which would improve overall plant heat rates. Heat pipe air heaters operate as regenerative exchangers in which heat from the hot flue gases is indirectly transferred to the cold air by means of a working fluid. The operation is illustrated in figure 1.4-3. The heat pipe tubes are partially filled with a heat transfer working fluid. The heat pipe tube is sealed under high vacuum to insure that the only gas inside the tube is the working fluid vapor. Passing hot flue gases over the lower end of the tube causes the working fluid to boil and the vapors to flow to the cold end of the tube. Cold air flowing over the top of the tube condenses the vapors releasing latent heat which heats the air. Since the heat pipes are mounted at a slight angle from horizontal ($5^o$ for the Milliken units), the condensed liquid flows by gravity back to the evaporator end of the pipe to repeat the cycle. Wall grooves or wicks are sometimes used inside the heat pipe tubes to improve wall wetting and heat transfer.

**FIGURE 1.4-3**
**HEAT PIPE CROSS SECTION**

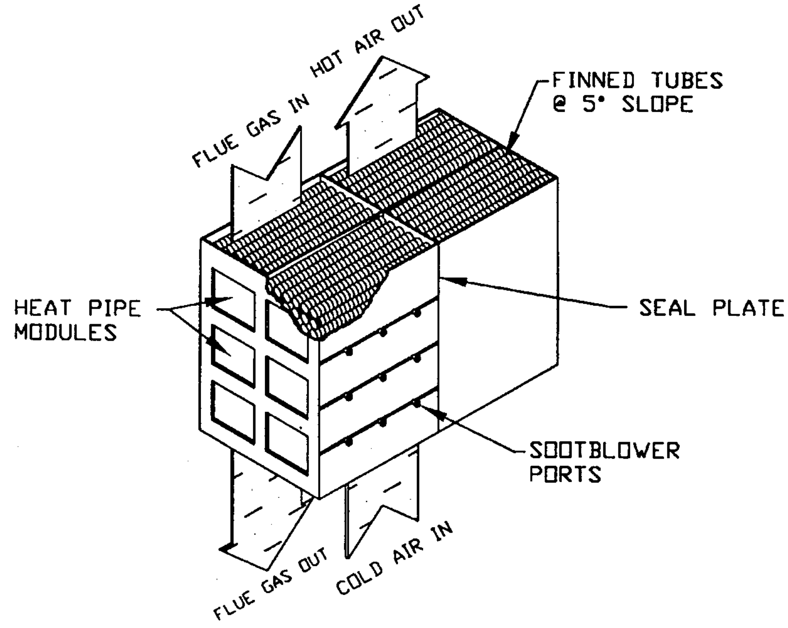


Inside a heat pipe, heat is transferred by boiling and condensing heat transfer mechanisms. For these mechanisms, heat transfer can proceed at extremely high rates as compared to conduction and/or convection. Because of this, a heat pipe can transfer several thousand times the amount of heat energy as solid copper for a given temperature difference. Due to the high internal heat transfer rates, individual heat pipes operate essentially isothermally with very small temperature differences between the hot and cold ends. This aids in achieving uniform outlet temperatures for heated and cooled process streams.

Depending upon the application, many different materials can be used as working fluids including: liquefied gases, water, hydrocarbons, chlorofluorocarbons, and liquid metals. The working fluid must be operated below its critical temperature, must be compatible with the tube wall material, and must be stable and not decompose under operating conditions. For the Milliken air heater design, naphthalene was selected for the high temperature sections and toluene used in the intermediate and cold end sections.

A full-scale heat pipe air heater consist basically of two ducts with a common wall. Individual heat pipe tubes extend through the common wall across both ducts (figure 1.4-4). Hot flue gases flow through one duct while cold combustion air flows through the other duct. The tubes are usually seal welded or gasketed in some fashion at the common wall to prevent air leakage between the flue gas and air sections. The ends of the tubes are free to expand or contract as necessary within the duct casing. By extending the individual tube surface through the use of fins, compact units can be designed.

**FIGURE 1.4-4**
**TYPICAL HEAT PIPE AIR HEATER CONSTRUCTION**



The main advantages of the heat pipe air heater design over tubular designs are: compactness, a lower potential for air leak development, and uniform temperature distribution across the heat transfer zone. The common wall divider between the flue gas and air sections is made of a thick, heavy metal plate which is unlikely to corrode through over the life of the unit. Additionally, each heat pipe tube provides a double barrier against air leakage. Should a tube become penetrated on the flue gas side due to corrosion, the tube would loose the charge of working fluid and become inactive. Air would not however flow into the flue gas section unless the air end of the tube also became punctured, an unlikely event. Finally, because each heat pipe operates isothermally along its length, the outlet temperatures for both the heated and cooled streams can be controlled more exactly and uniformly. This potentially could benefit utility air heaters by eliminating flue gas side cold spot areas and allowing operation at lower outlet temperatures due to tighter control of the cold-end heat transfer surface metal temperatures.

### Heat Pipe Commercialization Status

Prior to the Milliken demonstration project, heat pipe air heaters have been used in smaller coal fluidized-bed, gas, and oil boilers. Over 100 heat pipe air heaters have been installed, mostly on smaller industrial boilers and fired heaters. Many have been in operation for over 10 years. To date, the most relevant utility installation of heat pipe air heaters is at West Penn Power's Pleasant Station in Willow Island, WV, a 626 MW unit. The heat pipe is one of two primary air heaters. The heat pipe system has a capacity of 39.2 million Btu/hr, which is approximately half the size of the unit for the MCCTD project. The fuel used at Pleasant Station is Pittsburgh seam coal with a 3.2% sulfur content. The heat pipe system has been in service for over 7 years with excellent results, and it was over 4 years before the fins needed to be washed. The utility is very pleased with the heat pipe system's performance, especially the low maintenance and zero leakage.

### Significant Features of the Heat Pipe Air Heater Demonstration

The heat pipe air heater has wide potential market appeal. It is suited to any power generator, either utility or industrial, seeking 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 demonstration of heat pipe air heater technology will extend its applicability from fluidized bed boilers, oil fired boilers, and gas fired boilers to commercial-sized, conventional, bituminous coal-fired boilers.

The technical concerns associated with the use of the heat pipe air heaters include plant shutdown or low load operation due to heat pipe unavailability. Factors which may cause heat pipe unavailability include:

- corrosion of tubes due to $SO_3$ 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 high pressure drop and plugging.

These risk factors were addressed in the design of the air heater by considering corrosion resistant tubes where appropriate, by using conservative fouling factors in the design and by providing for adequate soot blowing coverage. These risks were mitigated by installing the heat pipe air heater system on only one of Milliken's two units.

The demonstration tests all aspects of the technology at commercial scale on a commercial coal-fired unit. Data collection, analysis and reporting performed during the operations phase includes on-stream factors, material balances, equipment performance thermal efficiencies. The data generated are directly applicable to other applications and provide valuable information to permit commercialization. The demonstration provides information concerning corrosion rates, the impact of fouling on heat transfer characteristics, the impact of fouling on gas-side pressure loss and the design and placement of soot blowers to minimize fouling.

The key benefits of the heat pipe air heater system, compared to conventional air heater technology include:

- Improved Heat Rate Due to Eliminating Air Leakage. As described above, both tubular and rotary regenerative (Ljungstrom®) air heaters allow significant leakage of combustion air into the flue gas downstream of the economizer. With the heat pipe system there is no (0%) leakage between the combustion air and the flue gas. The leakage reduces the flue gas temperature and causes corrosion and fouling of the air heater in areas of flue gas acid condensation. The leakage increases forced and induced draft fans 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.

- Improved Heat Rate and Reliability Due to Less Potential for Corrosion. Conventional regenerative (Ljungstrom®) 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. 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 areas. Because the distribution is poor and the difference in temperature is high, acids in the flue gas condense and tube corrosion occurs. 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 surface area is exposed to corrosive conditions. Therefore, flue gas acid condensation is reduced and corrosion and fly ash agglomeration ( and fouling) are greatly reduced.

- Flexible Design. Tube pitch and tube pattern can be designed to reduce fouling and cleaning. 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. The choice of tube and fin materials of construction sets 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.

- No Moving Parts. There are no drive assemblies 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.

### The CAPCIS Corrosion Control System

The installation of the CAPCIS corrosion control system together with the heat pipe air heater on Milliken Unit 2 was intended to demonstrate a system which optimizes the thermal efficiency of the boiler cycle by making on-line operating decisions based on instantaneous corrosion conditions of the flue gas equipment. The mechanism of corrosion in flue gas streams is dependent on a number of factors for which there is no control. Such factors include humidity, ambient air temperature and normal variations in fuel makeup. Normal practice has been to control system parameters based on an estimated acid dewpoint for the coal being fired. However, it has been shown that acid dewpoint alone may not necessarily be the point where unacceptable corrosion will occur. The MCCTD project intended to demonstrate that acceptable operation can occur with flue gas temperatures below the "acid dewpoint" by operating the heat pipe air heater with 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 provides a feed-back control signal from corrosion rate sensors in the flue gas stream. The thermal efficiency of the boiler is maximized while preventing corrosion by controlling the air heater outlet flue gas temperature. The flue gas exit temperature of the heater is controlled by bypassing the air side of the heater through a control damper. Having the CAPCIS system modulate the bypass dampers to adjust the flue gas exit temperature would have allowed 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.

### CAPCIS Commercialization Status

Since the late 1970's, numerous CAPCIS corrosion monitoring and surveillance systems have been installed around the world. Most of the early applications were used to investigate corrosion in low-temperature acidic condensation systems. Since 1980, CAPCIS has been working on the investigation of condensation corrosion in the low-temperature sections of a boiler plant. The work commenced with CEGB, British Coal, Esso Engineering Europe Ltd., and the Department of Trade and Industry. Since 1984, work has continued with EPRI in the USA and with Ontario Hydro in Canada on a variety of problems. More recently, CAPCIS has developed systems for monitoring in high temperature (up to 2000 $^{o}$F) environments, such as in combustion units and process heaters. The approach of providing a feed-back control signal from corrosion monitoring sensors in the flue gas stream to adjust the heat pipe air heater bypass damper setting has been confirmed to be feasible based on previous work on behalf of EPRI in the US and CEGB/PowerGen in Europe.

### Performance of the Heat Pipe Air Heater

The key features of the heat pipe air heater system which make it marketable are the improvement in boiler thermal efficiency over a regenerative air heater; zero leakage from air side to flue gas side; better outlet temperature control allowing for more heat recovery and lower flue gas outlet temperatures; passive design with no moving parts; lower erosion due to low flue gas velocities; lower flue gas and air side pressure drops; potential for improved ESP operation due to more uniform flue gas exit temperature profile; potential for increased heat transfer, reduced exit gas temperature and increased boiler efficiency due to the CAPCIS corrosion monitoring system; and easily replaceable modules. The demonstration of these features should encourage the widespread commercialization of high efficiency air heater systems. The demonstration size is at a scale which represents the same size as what would be expected in commercial applications for a 150 MW pulverized coal power plant. Because the demonstration is at full scale US utilities should be more willing to embrace the results than for a demonstration requiring scale-up.

The supplemental monitoring program described in Section 4.11 was conducted to evaluate the effects of operating conditions on heat transfer rate, air in-leakage and corrosion rate and to characterize the operation of the heat pipe, quantify its benefits and establish guidelines for purchase or use by other utilities. Velocity traverses were taken to investigate the uniformity of gas flow and its affect on overall heat transfer performance. Air leakage measurements were taken initially to verify zero leakage guarantee. Subsequently leakage was measured in conjunction with boiler efficiency measurements to monitor performance changes over time. Heat pipe thermal performance data were obtained in both clean and fouled conditions at full and low boiler loads. Special alternate material test heat pipes installed at inlet and outlet ends of the cold end module were periodically removed and analyzed for inert gas buildup, degradation of heat transfer fluid, extent of corrosion, erosion and scale buildup.

The results of the monitoring program, including a usable correlation between corrosion rate and flue gas temperature for variable air inlet temperatures, excess air and fuel sulfur content are presented in Section 4.11, providing valuable information to the utility industry for power plant management.

### Operability and Reliability

As described above, the heat pipe air heater concept is less susceptible to corrosion and fouling then regenerative and recuperative air heater designs which results in improved performance, higher reliability, lower maintenance and reduced generation of wastewater from washing. Section 4.11 also discusses the operating history of the Heat Pipe Air Heater demonstration with emphasis on ease of operation, frequency of process upsets, ease of recovery from such upsets and the incidence of solids buildup and corrosion. Specific problems encountered are discussed together with the solutions developed to eliminate them. The process's performance stability and load following performance are described. The maintenance history of the heat pipe is summarized and critical component failures are described and analyzed. The effectiveness and frequency of on-line and off-line cleaning are quantified. System reliability and availability are quantified. The observations made during periodic inspections are summarized with emphasis on the incidence and character of solids accumulation and corrosion which are critical to the viability of the heat pipe design concept. The data presented characterize the reliability, incidence of maintenance and ease of operation of the Heat Pipe Air Heater.

### Economics of the Heat Pipe Air Heater

Demonstration of the energy savings provided by a high efficiency air heater system and the CAPCIS corrosion monitoring and control system and control is a key feature of the project. Heat pipe air heaters are designed to provide enhanced air heater performance compared to the air heater technology commonly found in utility boiler applications. The heat pipe air heater system is designed to eliminate air heater leakage and reduce exit gas temperatures. The CAPCIS corrosion monitoring and control system enables operation at even lower exit gas temperatures while keeping corrosion rates within acceptable limits. This project demonstrates the energy efficiency and conservation gains achievable by incorporating this total system. The successful demonstration of power savings and improved thermal with high availability and low maintenance quantifies the potential for life cycle cost savings compared to conventional air heater designs.

Section 6 presents the estimated capital and operating and maintenance costs for the Heat Pipe Air Heater that were derived from the data collected during the demonstration. The results confirm the competitiveness of the process when compared to other commercially available air heater designs.

## NOxOUT® INJECTION (SNCR)

As originally configured the MCCTD project included combustion modifications for primary $NO_X$ emissions control and Nalco Fuel Tech's NOxOUT® selective non-catalytic reduction system (SNCR) to further reduce $NO_X$ emissions while retaining flyash salability. The NOxOUT® system utilizes urea injection in the post combustion zones of the boiler to reduce $NO_X$ emissions. The NOxOUT® system is a very energy efficient and low capital cost approach to controlling the emissions of nitrogen oxides produced in the combustion process. This technology, used by itself or in combination with combustion modification technologies, can provide an increase in the overall reduction of $NO_X$.

The NOxOUT® system was to be demonstrated on only one of the units at Milliken Station while combustion modifications were installed on both units, thus demonstrating the process's capability for incremental $NO_x$ emissions reductions beyond that achievable through combustion modifications alone. The site of the NOxOUT® demonstration was eventually shifted to Penelec's Seward Station to avoid undue duplication of efforts. Unfortunately, Seward Station was not equipped with a low NOx combustion system and the performance of the NOxOUT® system could only be demonstrated as a stand-alone $NO_X$ control technology.

### Description of the NOxOUT® Process Concept

The NOxOUT® process achieves $NO_x$ reduction by the reaction of $NO_x$ with urea injected into the post-combustion zones of the boiler to convert $NO_X$ into harmless nitrogen, carbon dioxide, and water. The urea is injected as an aqueous solution. The quantity of water used for dilution is typically set by the requirement to achieve a good distribution. The urea solution contained in storage normally contains 50% by weight of urea. This solution is then diluted on-line to the concentration for injection which may be in the range of 5 to 20% by weight of urea. In order to avoid scaling of the injectors and to avoid the need for water of high purity for dilution, an anti-scaling additive is used. This permits the use of ordinary service water for dilution. This anti-scalant combined with a dispersant for droplet size optimization is contained in the concentrated urea solution which is marketed under the trade name NOxOUT A ®.

The most critical parameters in the design of a NOxOUT® injection system are gas temperature, residence time, carbon monoxide concentration of the gas at the point of injection, uncontrolled $NO_x$ concentration, amount of $NO_x$ reduction required and ability to distribute chemical at the appropriate combination of temperature and residence time. Carbon monoxide concentration is almost as important as temperature because it is a measure of the concentration of reactive species in the gas phase, and the temperature window for reaction shifts to lower temperatures with increases in carbon monoxide concentration.

The first step in evaluating a potential application is a survey for gas temperature, carbon monoxide concentration and accessibility. This information is used in combination with other basic parameters such as fuel rate and excess air to construct a three dimensional, computational fluid dynamic (CFD) model of the boiler. The temperature-residence time profiles generated by this model are then used in a chemical kinetic model of the NOxOUT® process to predict the amount of $NO_x$ reduction and ammonia slip that can be expected under theoretical conditions. The output from the kinetic model is then recycled to the CFD model where chemical injection is simulated. This simulation permits selection of preferred injection locations and optimum parameters for injection. These parameters include average droplet size, droplet size distribution and droplet velocity. Preferred injectors for a specific application are then drawn from an array of injectors that have been previously characterized.

### NOxOUT® Injection (SNCR) Commercialization Status

The NOxOUT® SNCR process is licensed by Nalco Fuel Tech, a joint venture formed in 1990 by Nalco Chemical Co. and Fuel Tech N.V. (Fuel Tech N.V. has recently acquired the Nalco interest in the joint venture and the unit now operates as Fuel Tech, Inc.) Nalco Fuel Tech was formed to link a large chemical company having extensive utility and boiler experience with a technology that reduces air pollution in a highly effective, highly reliable manner without causing detrimental effects to the combustion equipment. Fuel Tech N.V. has performed research on enhancements of the urea injection concept initiated by the Electric Power Research Institute (EPRI) in 1976 and developed proprietary chemicals to permit urea injection over a broader temperature range and perfected the injection equipment and process configuration. In 1987, Fuel Tech became the exclusive agent for EPRI's urea injection technology and Nalco Fuel Tech was the exclusive licensing agent of this technology.

Commercialization of urea injection SNCR is well underway in the US. However, applications to conventional boilers prior to the MCCTD project have been limited to European boilers that have routinely fired low sulfur coals. In addition, the geometry of these boilers has been favorable for retrofitting the injection nozzle systems and in providing the required residence time for the chemical reactions between urea and $NO_x$ compounds to take place. These are two very important considerations when evaluating the retrofit potential of this $NO_x$ control technology.

The NOxOUT® process was first commercially applied on a corner-fired utility boiler owned by Rheinisch-Westfalisches Elektrizitatswerk, a German utility. In 1987, a number of tests for $NO_x$ reduction were initiated on a 150 MW, lignite-fired boiler at the Weisweiler Plant. The test objectives of up to 50% $NO_x$ reduction and an ammonia slip of less than 5 ppm were met over a range of operating conditions. In 1988, a commercial NOxOUT® system was installed on a 75 MW, lignite-fired boiler which had achieved a $NO_x$ emissions level of 150 ppm by the use of combustion modifications. Using the NOxOUT® technology, $NO_x$ emissions were further reduced to 90-98 ppm and ammonia slip was controlled to a level of less than 2 ppm through the combination of enhancer chemicals plus selective injection.

By 1991, the NOxOUT® technology was installed or in the planning stages on 30 boilers, with capacities ranging from 130,000 pounds of stream per hour to 900 million Btu/hr. The boilers include stokers and corner- and wall-fired furnaces. Fuels have included gas, wood, tires, municipal solid waste, oil, lignite and low-sulfur bituminous coals. Commercialization of this technology for more tightly designed boilers or those firing high-sulfur coals had not begun, nor had any substantial demonstration tests been performed on coal-fired boilers in the US.

### Significant Features of the NOxOUT® Demonstration

Prior to the MCCTD project SNCR processes using urea injection had achieved 30% to 60% reduction in $NO_X$ emissions on a full-scale, commercial, oil-fired utility boilers. The MCCTD project extends the application of this technology to utility-scale high sulfur coal-fired boilers in the United States. The MCCTD project originally intended to demonstrate the overall effectiveness of the NOxOUT® system in coordination with other boiler upgrades including combustion modifications, a coordinated plant control system, and a burner management system.

The incorporation of all these state-of-the-art features would have permitted the demonstration of several criteria including:

- Minimum 30 percent additional $NO_X$ reductions beyond that achievable with combustion modifications alone
- Improved cost effectiveness for $NO_X$ reduction
- Evaluation of effects of simultaneous operation of the $NO_X$ reduction technologies on air heater, ESP, scrubber operations and fly ash quality.

The relocation of the demonstration to Seward Station, which is not equipped with upstream $NO_X$ control technology or an FGD system, required modifying these objectives to some extent. NOxOUT® was evaluated as a standalone technology, as opposed to a technology in combination with combustion control upgrades. The demonstration attempted to identify maximum achievable $NO_x$ reductions using NOxOUT A® as a standalone technology while maintaining marketable fly ash. During periods of low fly ash sales (e.g., winter months) the maximum $NO_x$ reduction while maintaining less than 5 ppm of ammonia slip was to be demonstrated. The effects of NOxOUT® on air heater and ESP operations and fly ash quality were to be evaluated, but not its effects on scrubber operation.

This full-scale, long term demonstration was to provide answers to such utility industry issues as long term $NO_x$ emission rates, boiler-related impacts, operating and maintenance costs, effects on downstream equipment (air preheater, ESP) performance and the effects on sales potential of byproducts (fly ash). The planned scale (150MW) and duration of testing should be sufficient to resolve these concerns.

At an equivalent $NO_X$ emission rate, the MCCTD project originally intended to demonstrate the combining of combustion modifications with the NOxOUT® process to mitigate the adverse effects normally inherent with a single technology, including:

- ammonia slip with NOxOUT®,
- carbon carry-over with combustion modifications, and
- waterwall slagging with combustion modifications.

The control of these effects is critical for utilities, like NYSEG, that are dedicated to maximizing the utilization and sale of byproducts, such as fly ash and gypsum. Excessive amounts of either ammonia slip or carbon carry-over would contaminate the fly ash collected in the electrostatic precipitators and prevent the continued sale of the fly ash. Fly ash sales are used by utility companies to reduce landfill requirements. Loss of these sales would greatly increase the landfill requirements for the fly ash, which would be detrimental to the overall environmental goals of the US.

- Improved $NO_X$ Reduction. Since the injection of the NOxOUT® solution does not impact the combustion process, the NOxOUT® system can be applied in conjunction with all combustion modification technologies to improve reductions in $NO_X$. NOxOUT® used in this fashion can reduce $NO_X$ by up to 30%. This further reduction is important in that combustion modifications are not expected to be able to reduce $NO_X$ emissions to the 0.45 lb/MM Btu level in all applications required by the CAAA. Also, local or regional regulators may require stricter emission limits than the CAAA. These lower limits would only be possible through the utilization of combined control technologies such as is feasible with the NOxOUT® system.

- Low Capital Cost Requirements. The NOxOUT® system is a low capital cost $NO_X$ reduction method. The only capital equipment included in this process are 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.

- Enhanced Temperature Characteristics. The NOxOUT A® enhanced urea solution provides improved temperature characteristics as compared to urea alone. Addition of proprietary chemical enhancers to the solution has succeeded in broadening and/or shifting the optimum temperature at which the solution is effective. This allows increased reductions of $NO_X$ through staging of the chemical injection at various elevations in the boiler. This staged approach allows high $NO_x$ removal efficiencies with very low ammonia slip. Also, since the location becomes somewhat less critical it is expected that no additional injection points would be required on a boiler besides the original inspection ports.

- Low Ammonia Slip. A key feature contributing to the marketability of the NOxOUT® technology is the consistent rate of $NO_x$ removal with a very low ammonia slip. Maintaining low ammonia slip is critical to the control of air heater plugging and for permitting the sale and use of the fly ash as a pozzolanic material in the formation of concrete will not be affected. The chemical enhancers included in the NOxOUT A® urea solution allow ammonia slip to be maintained below 2 ppm. Typically, a simple urea injection will have significant levels of ammonia being formed as a side reaction to the $NO_X$ 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. NOxOUT® technology can be used very effectively on a wide range of boiler sizes and configurations.

## Commercialization Aspects

Nalco Fuel Tech believes that this project will provide key impetus for the further commercialization and acceptance of the NOxOUT® system. This belief is supported by several key criteria demonstrated by this project. These criteria are:

- US Utility Application: The demonstration of this technology on a US utility boiler provides the credibility required to establish it as a commercially viable option in this market. The US utility market is close-knit and successful application of a product in the market is highly regarded. Utilities use different sources of information from research organizations such as EPRI or computer information exchanges to research previous utility applications of a technology prior to acceptance of that technology. A successful demonstration project at Seward Station provides the base required for acceptance in this market.

- Compliance with Emission Goals: The project demonstrates the economical reduction of $NO_X$ to below the 0.45 lb/MM Btu limit prior to the 1997 deadline for the establishment of new regulatory limits on $NO_X$ emissions. Since this new limit will be based on the best available technology with consideration for costs and energy and environmental impacts, this demonstration provides a baseline by which this technology can be compared.

- High Sulfur Application: Prior to the MCCTD project the NOxOUT® technology was installed, or in the planning stage, on approximately 30 boilers ranging in size up to 900 million Btu/hr. However, none of these installations was with high-sulfur coal. The MCCTD project is the first commercial demonstration of the NOxOUT® technology on a furnace firing US high-sulfur bituminous coal. Demonstration on a high sulfur application is critical to wide-spread commercialization of the NOxOUT® process. Application of urea injection SNCR technology to tighter designed boilers firing high sulfur coals presents risks of boiler fouling and fly ash contamination due to the potential for ammonia slip. As a consequence, ammonia slip will be aggressively monitored. In high sulfur coal applications, higher levels of $SO_3$ can react with the excess ammonia, forming ammonium bisulfate salts which can foul downstream heat exchangers and contaminate the fly ash. Contamination of fly ash with ammonium bisulfate during the demonstration period could jeopardize fly ash sales. Proper precautions in storing, handling and feeding urea are necessary to assure that injection rates do not become excessive causing unacceptable levels of ammonia slip or creating the potential for ammonium salts formation which would foul the boiler heat exchangers and contaminate the fly ash. If the unit modifications are properly designed and the system is operated within design parameters, ammonia slip and the potential for ammonium bisulfate formation should be low and fly ash contamination should not be a problem.

The NOxOUT® technology has been demonstrated on larger boilers and on $NO_x$ levels higher than the MCCTD project. However, this demonstration is the first to combine all of the individual possibilities on one boiler. This installation demonstrates the reduction in $NO_x$ emissions achievable with NOxOUT® while maintaining an ammonia slip of 2 ppm or less on a tangentially fired boiler, firing high sulfur sub-bituminous coal.

There are no other installations of this technology which compare in applicability or impact on commercialization potential.

## Performance of the NOxOUT® System

The NOxOUT® process test program was designed to monitor operating conditions for process control, to evaluate the effect of operating conditions on $NO_x$ reduction efficiency, fly ash quality, load following capability, annual operating and maintenance costs and ammonia slip and to provide operation and performance data to confirm the 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 $NO_x$ achievable, (2) short-term $NO_x$ emissions, (3) 30-day rolling average $NO_x$ emissions, and (4) annual $NO_x$ emissions.

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 are performed using standard commercial industrial process monitors. $NO_x$, $O_2$ and CO concentrations in the flue gas stream are 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.

The anticipated test results were expected to verify the process's capability for high $NO_x$ removal efficiency and adequate load following capability with low ammonia slip and minimal impact on fly ash quality. The results were not available at the time of publication and will be the subject of a future topical report.

## Operability and Reliability of the NOxOUT® Process

The future topical report will also discusses the operating history of the NOxOUT® process demonstration with emphasis on ease of operation, frequency of process upsets and ease of recovery from such upsets. Specific problems encountered will be discussed together with the solutions developed to eliminate them. The process's performance stability and load following performance will be described. Critical component failures will be described and analyzed. System reliability and availability will be quantified. The observations made during periodic inspections will be summarized with emphasis on the degree of solids accumulation in the downstream equipment. The data presented will characterize the reliability, maintenance requirements and ease of operation during plant transients.

## Economics of the NOxOUT® Process

The future topical report will also present the estimated capital and operating and maintenance costs for the NOxOUT® process derived from the data collected during the demonstration. The results should confirm the competitiveness of the process when compared to other commercially available $NO_x$ control systems.

## COMBUSTION MODIFICATIONS

The MCCTD project includes a $NO_x$ emissions control strategy consisting of combustion modifications, advanced 3Ädimensional combustion modeling, and boiler expert computer system to minimize $NO_x$ emissions and to simultaneously optimize boiler thermal efficiency. This $NO_x$ emissions control scheme is unique it that it combines these three technologies to minimize $NO_x$ emissions while optimizing boiler thermal efficiency and maintaining low carbon levels in the ash.

Milliken Station is the first retrofit application on a utility boiler equipped with an FGD system producing byproduct gypsum and salable fly ash. The carbon level in the ash is critical to fly ash sales and could adversely affect gypsum color. Marketable fly ash must contain less than five percent by weight of carbon. The current Milliken fly ash sales contract limits the carbon content to 4 wt%.

The full scale application of this combination of technologies demonstrates the effectiveness of these subÄsystems to function as a unit to achieve the stated goals. The scale of the demonstration and duration of testing will resolve any private sector concerns as to the efficacy of the technology.

Combustion modifications, including replacing the existing conventional tangential firing system with the Low $NO_X$ Concentric Firing System (LNCFS) furnished by ABB CE Services, were installed at NYSEG's expense on both Milliken units for control of $NO_x$ emissions. These modifications were expected to reduce $NO_X$ emissions by about 20%.

The PCGC-3 combustion model, a 3Ädimensional coal combustion code designed to predict gas flow profiles, heat transfer, and $NO_x$ formation to optimize air/fuel mixing for high carbon burnout, was used to optimize the design of the combustion modifications. The model was developed by the Advanced Combustion Engineering Research Center (ACERC). Through the use of the model, the project was able to demonstrate on the utility scale the validity of the model and quantify the $NO_X$ reduction achieved through its use.

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, installed on both Milliken units 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.

### Low $NO_X$ Concentric Firing System

The Low $NO_X$ Concentric Firing System (LNCFS), furnished by ABB CE Services, maximizes the $NO_X$ reduction capabilities of existing tangential firing systems while minimizing unit modification. The LNCFS uses a combination of two techniques to reduce $NO_X$, bulk furnace staging and early controlled coal devolatilization.

Bulk furnace staging takes a portion of the combustion air, which is introduced at the fuel burning zone, and diverts it to retard air and fuel mixing. With conventional tangential firing, the introduction of excess combustion air during the early stages of coal devolatilization contributes significantly to the formation of $NO_X$. The LNCFS maximizes the bulk staging concept by using both overfire air and concentric firing. Staged combustion is produced by introducing a portion of the secondary air, called overfire air, above the primary firing zone. This is accomplished by utilizing a close-coupled overfire air system in which the overfire air nozzles are located in the top elevations of the main windboxes, and a new separate overfire air windbox which is installed above the existing windbox. The concentric firing system utilizes a re-direction of the secondary (auxiliary) air which is admitted in the main firing zone, diverting it away from the coal stream. In this manner, combustion stoichiometry is reduced by preventing the fuel stream from entraining with the air stream during the initial stages of combustion. Fuel nitrogen conversion is reduced, while maintaining appropriate oxidizing conditions along the furnace walls. The introduction of air in the concentric firing circle is accomplished with the installation of offset air nozzles.

Another important design feature incorporated into the LNCFS is the technique of early fuel ignition. Initiating the combustion point very close to the fuel nozzle produces a stable volatile matter flame which is more easily controlled under sub-stoichiometric firing conditions. A two-piece "flame attachment" type coal nozzle tip is used to promote this strong primary flame.

### PCGC-3 Combustion Model

The PCGC-3 Combustion model is a comprehensive computer model 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 US 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 PCGC-3 model, a 3Ädimensional coal combustion code, predicts gas flow profiles, heat transfer, and $NO_x$ formation to optimize air/fuel mixing for high carbon burnout. The model incorporates the influence of fluid dynamics in modeling the time, temperature and flow history in the boiler and includes submodels to incorporate coal devolitization, char burnout, heat transfer and $NO_x$ formation. The model was used to optimize the operation of the combustion equipment, especially the design of the combustion modifications to the furnace. The model fluid mechanics provisions were used to optimize the air fuel mixing to achieve 0.45 lbs/mm Btu $NO_x$ emissions with less than three percent carbon in the ash while optimizing thermal efficiency. Through the use of the model, the MCCTD project was able to demonstrate on the utility scale the validity of the model and quantify the $NO_X$ reduction achieved through its use. Milliken is the first commercial application of the PCGCÄ3 code to the design of a retrofit low $NO_x$ combustion system.

### 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 $NO_x$, $SO_2$, $O_2$, CO, $CO_2$, 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.

### Performance of the Combustion Modifications

Section 4.4 describes the testing program that was used to demonstrate the effectiveness the MCCTD's emissions control strategy in reducing $NO_x$ emissions while simultaneously optimizing boiler thermal efficiency and meeting LOI requirements for flyash sales. The test program consisted of four series of tests: (1) diagnostic, (2) performance, (3) long-term, and (4) verification.

The diagnostic tests were designed to provide short-term parametric data with respect to the effects of boiler and operating variables on $NO_X$ emissions and loss-on-ignition (LOI). Baseline diagnostic testing was conducted to characterize system performance prior to installation of the combustion modifications. Post-installation diagnostic testing was conducted to characterize the influence of certain design variables and to optimize system performance.

Performance or characterization tests were conducted in conjunction with ESP testing. The measurements in these tests included CEM single-point sampling at the stack, particulate characteristics data, boiler efficiency data, and pulverized coal fineness data.

Long-term tests used statistical analysis methods for evaluation of long-term data developed by the Control Technology Committee of the Utility Air Regulatory Group (UARG). These methods were used to determine the achievable emissions limit of a control technology. These tests included CEM stack sampling for 51-60 days with each day consisting of at least 18 hourly averages to predict the 30-day rolling average emission limit.

Verification tests were conducted to test the predictive correlations derived from the statistically designed baseline and post-retrofit diagnostic tests. The verification tests were condensed versions of the diagnostic tests, and included repetitions of selected tests, following the long-term tests.

The testing results reported in Section 4.4 quantify the effectiveness the MCCTD's emissions control strategy in reducing $NO_x$ emissions while simultaneously optimizing boiler thermal efficiency and meeting LOI requirements for flyash sales.

### Operability and Reliability of the Combustion Modifications

Section 4.4 discusses the operating history of the LNCFS demonstration with emphasis on ease of operation, frequency of process upsets and ease of recovery from such upsets. Specific problems encountered are discussed together with the solutions developed to eliminate them. The process's performance stability and load following performance are described. Critical component failures are described and analyzed. System reliability and availability are quantified. The data presented confirm high reliability, low maintenance and ease of operation during plant transients.

### Economics of the Combustion Modifications

Section 6 presents the estimated capital and operating and maintenance costs for the Combustion Modifications that were derived from the data collected during the demonstration. The results confirm the competitiveness of the process when compared to other commercially available $NO_x$ control systems.

## SUMMARY

In summary, the MCCTD project has tested all significant aspects of the demonstration technologies at commercial scale on a commercial coal-fired unit. Data collection, analysis and reporting performed during the operations phase included on-stream factors, material balances, equipment performance, efficiencies and $SO_2$ and $NO_x$ emission levels. The data generated are directly applicable to other applications. The demonstration has significantly reduced the risks and concerns associated with these technologies and provides valuable information to permit their commercialization.

## 1.5 DOE'S ROLE IN PROJECT

The Milliken Clean Coal Technology Demonstration (MCCTD) Project was managed by a NYSEG Project Manager. This individual was the principal contact with DOE for matters regarding the administration of the Cooperative Agreement between NYSEG and DOE. The DOE Contracting Officer was responsible for all contract matters, and the DOE Contracting Officer's Technical Project Officer (TPO) was responsible for technical liaison and monitoring of the project.

DOE was responsible for monitoring all aspects of the project and for granting or denying approvals required by the Cooperative Agreement. The DOE Contracting Officer was DOE's authorized representative for all matters related to the Cooperative Agreement.

The DOE Contracting Officer appointed a Technical Project Officer (TPO) who was the authorized representative for all technical matters and had the authority to issue "Technical Advice" to:

- Suggest redirection of the Cooperative Agreement effort, recommend a shifting of work emphasis between work areas or tasks, or suggest pursuit of certain lines of inquiry which assist in accomplishing the Statement of Work.
- Approve all technical reports, plans, and items of technical information required to be delivered by the Participant to the DOE under the Cooperative Agreement.

The DOE TPO did not have the authority to issue technical advice which would have:

- Constituted an assignment of additional work outside the Statement of Work.
- In any manner caused an increase or decrease in the total estimated cost or the time required for performance of the Cooperative Agreement.
- Changed any of the terms, conditions, or specifications of the Cooperative Agreement.
- Interfered with the Participant's right to perform the terms and conditions of the Cooperative Agreement.

All technical advice was required to be issued in writing by the DOE TPO.

NYSEG had the primary responsibility for reporting to and interfacing with the DOE. NYSEG was responsible for all phases of the Project. NYSEG was the primary liaison between the DOE and all other participant organizations. The following organizations interacted effectively to meet the intent of the PON and to assure a timely and cost-effective implementation of the MCCTD project through startup and operation.

- New York State Electric & Gas Corporation (NYSEG)
- Saarberg-Hölter-Umwelttechnik GmbH (SHU)

- Stebbins Engineering and Manufacturing Company (Stebbins)
- CONSOL, Inc.
- Nalco Fuel Tech
- ABB Air Preheater, Inc.
- DHR Technologies, Inc.

The total project encompassed 75 months.

Two budget periods were established. Consistent with P.L. 101-512, DOE obligated funds sufficient to cover its share of the cost for each budget period. Throughout the course of this project, reports dealing with the technical, management, cost and environmental monitoring aspects of the project were prepared by NYSEG and provided to the DOE.

# 2.0 TECHNOLOGY DESCRIPTION

## 2.1 DESCRIPTION OF THE DEMONSTRATED TECHNOLOGY

### 2.1.1 INTRODUCTION

The Milliken Clean Coal Technology Demonstration Project provided significant reductions in emissions of sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_X$). The plant retrofits and upgrades for NYSEG's Milliken Station demonstrated several innovative technologies that reduce emission of these gases and air toxics.

A particularly attractive feature of the Milliken Clean Coal Technology Demonstration Project was the energy efficiency of the plant upgrades. The integrated package of plant modifications provided excellent environmental characteristics while retaining the high energy efficiency of Milliken Station, historically one of the 20 most efficient generating stations in the United States. At other plants upgraded to reduce environmental emissions, energy efficiency was severely degraded (station heat rate Btu/kWh increased). This project sought to minimize such heat rate penalties.

The overall project goals were:

- 98% $SO_2$ removal efficiency using limestone while burning high-sulfur coal.
- $NO_X$ emission reduction by combustion modifications.
- Demonstration of $NO_X$ reductions using NOxOUT® selective non-catalytic reduction technology (SNCR) in combination with combustion modifications.
- Production of marketable byproducts to minimize solid waste disposal including
    - Commercial-grade gypsum
    - Calcium chloride brine
    - Fly ash
- Zero wastewater discharge.
- Maximum station efficiency using heat pipe air heater system and low power consuming scrubber system.
- Space-saving design.

The project used two identical units. Technologies were demonstrated on either one or both of the units to maximize the comparison of innovative energy and environmental management features. In the original project plan all demonstration features of the Milliken Clean Coal Technology Project were to be integrated in Milliken Station Unit 2. The site of the NOxOUT® SNCR process demonstration was eventually relocated to Penelec's Seward Station.

By incorporating this combination of innovative technologies into one unit, the project was able to demonstrate excellent pollution abatement with a high level of energy efficiency and conservation not possible with many competing technologies.

In addition, the sulfur control process chosen for Unit 2 was shared with Unit 1, to demonstrate a unique below-stack split absorber flue gas desulfurization (FGD) design. By combining sulfur control in this way, a cost effective station approach resulted in ultra-high sulfur removal efficiency of the chosen FGD process to significantly reduce the sulfur emissions from both units.

## DEMONSTRATION TECHNOLOGIES SELECTED FOR BOTH UNITS 1 AND 2

To accomplish the project goals, NYSEG selected demonstration technologies offering substantial improvements in environmental emissions. The technologies demonstrated on both Milliken Station Units 1 and 2 included:

- The Saarberg-Hölter Umwelttechnik GmbH (SHU) formic acid enhanced wet limestone FGD process. This technology, originated in Germany, promised superior energy conservation capabilities, ultra-high sulfur removal efficiency (up to 98 percent) on a plant fired with high sulfur (greater than 3 percent) eastern sub-bituminous coal, ease of operations and high reliability. The project was intended to further the commercialization of the SHU process in the US by using American companies to bring the design to US utility industry standards and operating practice. The project was the first to install the SHU FGD absorbers directly below the flues. It was also the first demonstration of the split module cocurrent / countercurrent absorber concept utilizing Stebbins tile-lined FGD construction methods.

- A zero wastewater discharge FGD system which produces wallboard quality byproduct gypsum along with a marketable calcium chloride byproduct;

- Enhanced removal of hazardous air pollutants;

- Cost-effective compliance with the $NO_X$ emission control provisions of the Clean Air Act Amendments through the use of combustion modifications in combination with improved boiler controls; and, finally,

- The potential of improved $NO_X$ reduction using the Advanced Combustion Engineering Research Center PCGC-3D model to optimize the design of the $NO_X$ combustion retrofit components.

## ADDITIONAL DEMONSTRATION TECHNOLOGIES FOR UNIT 2

Additional demonstration technologies were applied to an individual unit. NYSEG selected demonstration technologies offering substantial improvements in energy conservation for Unit 2, providing one of the most completely integrated, and highly efficient clean air upgrade demonstrations in the world. In addition to the SHU/Stebbins retrofits summarized above, Unit 2 was modified to demonstrate the following:

- The improved energy efficiency and energy conservation aspects of a heat pipe air heater with temperature control employing a CAPCIS corrosion monitoring system.

The original project plan also included modifying Unit 2 to demonstrate cost-effective compliance with the $NO_X$ emission control provisions of the Clean Air Act Amendments through the use of combustion modifications in combination with improved boiler controls and the NOxOUT® selective non-catalytic reduction system. As noted above, the NOxOUT® demonstration was ultimately relocated to Penelec's Seward Station.

## PROCESS CONCEPT AND HOW THE MCCTD PROCESS TECHNOLOGIES OPERATE

Three diagrams provide an overview of the demonstration project. First, a summary profile of the project scope is shown in figure 2.1-1. This figure illustrates all of the required project segments covered by the MCCTD. This diagram is followed by a process block diagram, figure 2.1-2, which further describes the integration of the overall project. Later in this section, the operation of each of the major technologies that comprise the project is detailed. The third diagram, figure 2.1-3, illustrates the location of the demonstration technologies on the site plan.

The process block diagram, shown as figure 2.1-2, illustrates how Milliken Station was used to demonstrate the full complement of project features. By incorporating these technologies into both units, a cost effective strategy was developed to meet the goal of overall pollution abatement with increased energy efficiency and conservation. Both Unit 1 and Unit 2 were used to demonstrate the commercialization aspects of the split module absorber, providing the first commercial demonstration of a split cocurrent / countercurrent SHU absorber.

# FIGURE 2.1-1
# PROJECT PROFILE

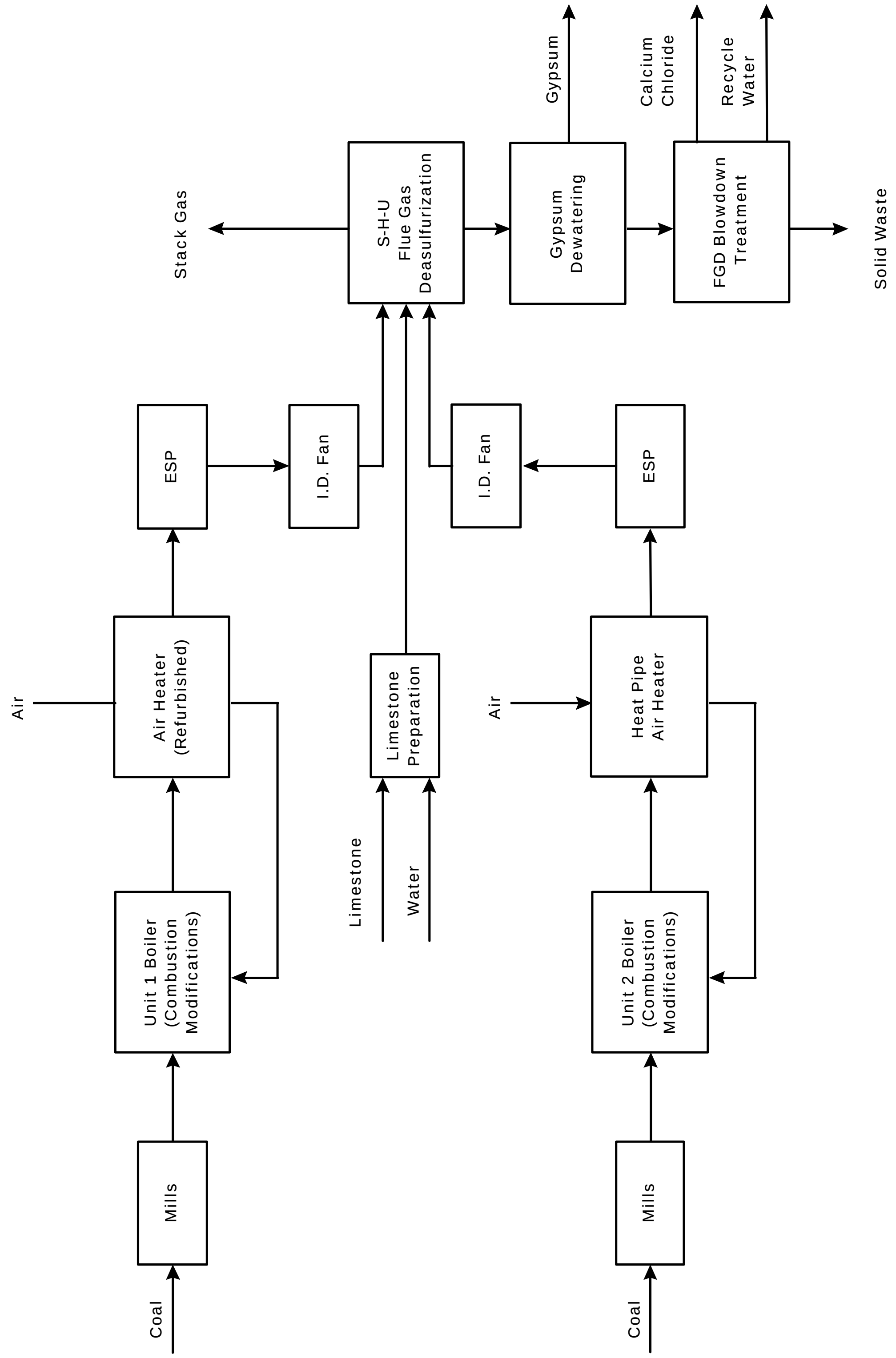
| SEGMENT OF PLANT | MCCTD PROJECT SCOPE |
|---|---|
| Raw Coal<br>↓<br>↓<br>↓<br>↓ | ·change to high sulfur Eastern coal |
| **PreCombustion**<br>↓<br>↓<br>↓<br>↓<br>↓ | ·change mills to handle new coal |
| **Combustion**<br>↓<br>↓<br>Flue Gas<br>↓<br>↓<br>↓ | ➢$NO_X$ combustion modeling<br>·combustion modifications for primary $NO_X$ emissions |
| **Post Combustion**<br>↓<br>↓<br>↓<br>↓<br>↓<br>Clean Flue Gas | ➢first US SHU demonstration<br>➢first US below-stack SHU absorber<br>➢first split SHU absorber<br>➢first utility Stebbins tile cocurrent/countercurrent absorber<br>➢first $NO_X$OUT® in high sulfur coal-fired utility furnace for $NO_X$ emission control (relocated to Seward Station)<br>➢first coal-fired heat pipe air heater with CAPCIS corrosion monitoring<br>·ID fans<br>·precipitator upgrade<br>·ductwork |
| **Balance of Plant Needs** | ·blowdown treatment<br>·power feeds to new equipment<br>·Unit 1 air heater upgrade<br>·control system upgrade<br>·electrical system upgrade |

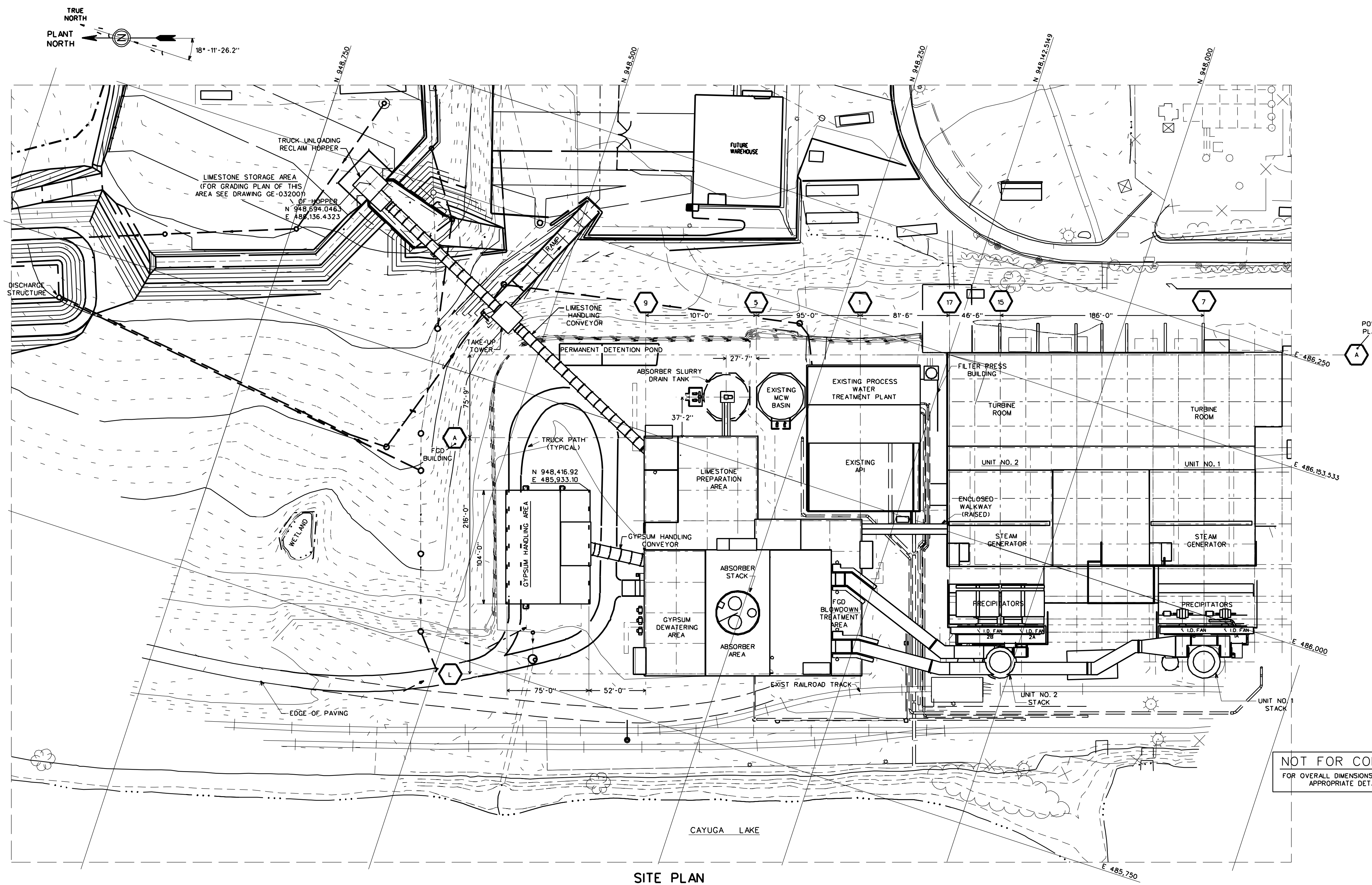
Legend:

➢novel technology in need of commercial demonstration

·commercial technology required in plant to support the demonstration of the novel technology

# FIGURE 2.1-2
# PROCESS BLOCK DIAGRAM FOR THE MCCTD PROJECT





SITE PLAN

NOT FOR CONSTRUCTION
FOR OVERALL DIMENSIONS AND LOCATIONS SEE APPROPRIATE DETAIL DRAWINGS.

REFERENCE DRAWINGS:

| | |
|---|---|
| GE-034520 | PLAN - ELEVATION 394'-0"<br>GENERAL ARRANGEMENT |
| GE-22285 SH 1 | EXCAVATION PLAN - PLANT AREA<br>SITE PREPARATION |
| GE-032001 SH 1 | LIMESTONE STORAGE AREA<br>GRADING PLAN |
| FMC CORPORATION<br>DWG • JK6191-1 | PLOT PLAN OF LIMESTONE AND<br>GYPSUM HANDLING SYSTEMS |

Gilbert Commonwealth Companies

| MECH. | ELECT. | STRUCT. | I & C | STRESS |
|---|---|---|---|---|
| ELB | | | | |
| DRAWN BY | CHECKED BY | ENGINEER | SUPERVISING ENGINEER | |
| TWB | NIA | | | |

0-DW-221-002-045

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DESIGN --/--/--
ENGRG --/--/--
RELEASE APPROVAL --/--/--
AUTHORIZED BY --/--/--

NYSEG
GENERATION DEPT.
BINGHAMTON, N.Y.

TITLE: FLUE GAS DESULFURIZATION SYSTEM
GENERAL ARRANGEMENT
SITE PLAN
MILLIKEN / UNITS 1 & 2

SCALE 1/32"=1'-0
DRAWING NO. GE - 034500
SHEET NO.

FILE NAME
$$$$$SYTME$$$$$$
DGNSPEC$$$$$$$$$$$$$$$$$$$$$

As noted, a main feature of this project was the demonstration of retrofit of both $SO_2$ and $NO_X$ control systems to a plant with minimum impact to the overall plant heat rate. To accomplish this, energy efficient technologies were selected for integration into the project. The estimated overall project energy balance is shown in table 2.1-1.

### TABLE 2.1-1

### PROJECT ENERGY BALANCE ESTIMATE

| TECHNOLOGY | POWER SAVINGS | HEAT RATE SAVINGS |
|---|---|---|
| SHU FGD and all Auxiliaries | -4.04 MW | -120Btu/kWh |
| Thermal Performance Advisor (0.75% Heat Rate) Advisor | | 70 Btu/kWh |
| Heat Pipe | | |
| Min 20°F decrease in Exit Gas Temperature (0.5% Heat Rate Improvement) | | 47 Btu/kWh |
| 16% Reduction in Air Flow Due to Leakage (Fan Power savings of 452 BHP) | 337 KW | 10 Btu/kWh |
| $NO_X$ System | | ~0 |
| | NET HEAT RATE SAVINGS = | 7 Btu/kWh |

**Current Heat Rate =** **9,422 Btu/kWh**
**Modified Heat Rate =** **9,415 Btu/kWh**

### 2.1.2 SHU ADVANCED FGD SYSTEM

The SHU process is the only developed wet limestone FGD process which is specifically designed to employ the benefits of low pH operation, formic acid enhancement, single loop, cocurrent / countercurrent absorption and in-situ forced oxidation.

#### SHU PROCESS FEATURES

The project was designed to demonstrate that SHU has succeeded in creating a process with the following features:

- ultra-high $SO_2$ removal efficiency (up to 98 percent) with limestone,
- low limestone reagent consumption,
- excellent stability and ease of operation during load changes and transients,
- low production of scrubber blowdown,
- freedom from scaling and plugging problems,
- high availability,
- low maintenance requirements,
- wallboard grade gypsum byproduct and
- increased energy efficiency and conservation compared to competing FGD technologies.

For Milliken Units 1 and 2, a single-train FGD absorber was installed for each of the two boilers with common auxiliary equipment.

#### SHU PROCESS CHEMISTRY

In the SHU process, $SO_2$ is absorbed from the flue gas by the recycle slurry and reacts to form bisulfite and hydrogen ions, according to the reaction:

$$\mathbf{SO_2+H_2O \rightarrow HSO_3^{-}+H^{+}} \qquad \textbf{(1)}$$

Small amounts of formic acid, HCOOH, are added to the slurry. Formate ions in solution react with the $H^+$ to buffer the solution (as shown in reaction (2)), thereby maintaining the pH between 4.0 and 5.0 in the cocurrent spray zone and between 4.2 and 5.0 in the countercurrent spray zone.

$$\mathbf{H^{+}+COOH^{-} \leftrightarrow HCOOH} \qquad \textbf{(2)}$$

As a result of adding formic acid, $SO_2$ is efficiently absorbed throughout the entire spray zone. Maintaining the slurry in the pH range of 4.0 to 5.0 ensures the formation of calcium bisulfite, the water soluble form of calcium and sulfur.

Limestone added to the recycle slurry is the source of calcium ions that precipitate sulfur-containing ions. Formic acid reacts with limestone to produce a recycle slurry with calcium ion concentrations much higher than those found in conventional limestone FGD processes (see reaction (3)).

$$\mathbf{CaCO_3+2HCOOH \rightarrow Ca^{+2} + 2COOH^{-}+H_2O+CO_2} \qquad \textbf{(3)}$$

High natural oxidation readily occurs throughout the spray zone. Additional (forced) oxidation occurs in the absorber reaction tank, without the need for an acidifying step. Dissolved oxygen in the recycle slurry reacts to form sulfate ions according to reaction (4).

$$2HSO^{-}_{3}+O_2 \rightarrow 2H^{+}+2SO_4^{-2} \qquad (4)$$

The calcium ions present in solution combine with the sulfate ions to produce gypsum, according to reaction (5).

$$Ca^{+2}+SO_4^{-2}+2H_2O \rightarrow CaSO_4 \cdot 2H_2O\downarrow \qquad (5)$$

For all load conditions, the SHU process with its buffered slurry operates within the pH range that precludes sulfite formation. This greatly reduces the operating and maintenance requirements compared to unbuffered processes. Unbuffered processes frequently require large staffs for operation and maintenance and suffer reduced availability due to forced outages to clean the absorbers.

The ability to operate in the non-scaling mode, even during transients, may be the single biggest advantage to low pH buffered absorption and is an extremely important consideration when operating the plant in a cycling mode or burning coals with wide variations in sulfur content.

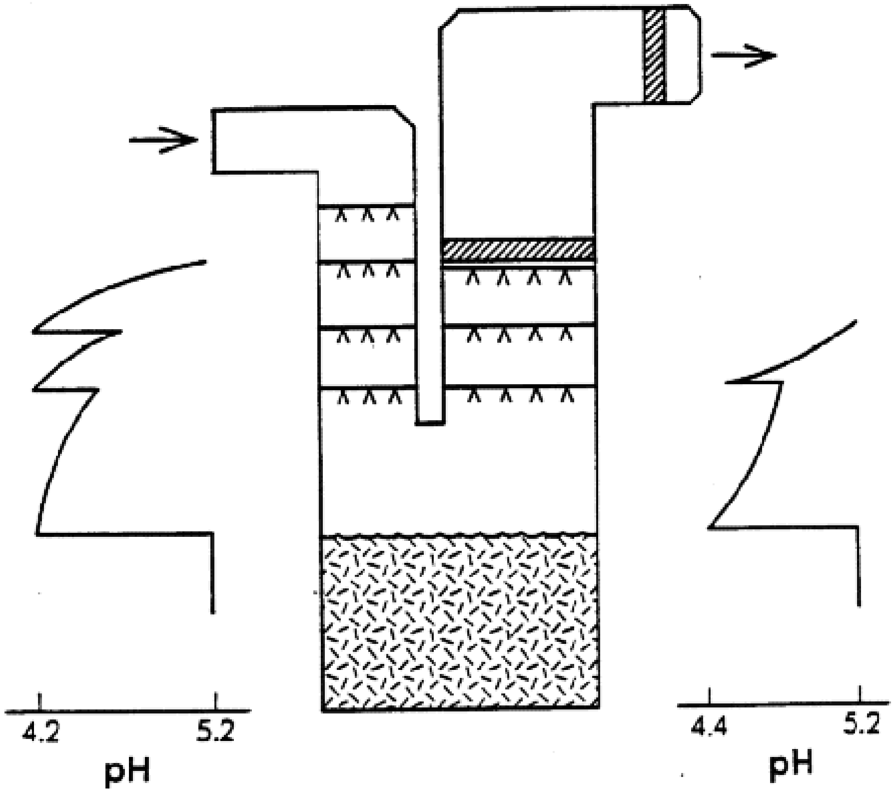
The buffered operation of the cocurrent / countercurrent absorber permits the absorption / oxidation reaction to occur at a much lower pH than in unbuffered countercurrent absorbers. Low pH operation avoids scale formation and forms the easy-to-oxidize bisulfite ion. The large gypsum crystals that form in the scrubber reaction tank are easy to dewater, and desired by wallboard manufacturers. Operation of the FGD absorption / oxidation reaction in the pH range of 5.5 to 6.0, the case for many competing processes, causes a risk of severe scale formation. In these competing processes, process control of pH is difficult and a frequent consequence of poor pH control is severe scaling. SHU developed the combination cocurrent / countercurrent absorber to operate in the pH range of 4.0 to 5.0. Scaling is thus avoided and pH control is not critical.

The cocurrent / countercurrent absorber with its multi-level spray system maintains an optimum pH range for bisulfite formation throughout both stages as figure 2.1-4 illustrates.

Typically, in the cocurrent section, the pH at the top of the spray zone is 5.0 and drops to 4.0 near the bottom of the spray zone. In the countercurrent section, where residual $SO_2$ is removed, the pH drops from 5.0 to approximately 4.4 to 4.2.

## FIGURE 2.1-4

## COCURRENT/COUNTERCURRENT ABSORBER PREVENTS HIGH pH ZONES THAT WOULD BE PRONE TO SCALING



## SHU PROCESS DESCRIPTION

### Flue Gas Flow

For the MCCTD project flue gas from the ESP is discharged through new ID fans which are required to overcome the combined pressure loss of the absorber, ductwork and new wet chimney. Refer to figure 2.1-5. New ID fans were chosen to minimize heat rate impact, control problems and cost, compared to the use of booster fans. Flue gas is ducted from the fans to the absorber modules. Flue gas enters at the top of the cocurrent section where it is quenched by water sprays. The gas is then contacted with recycle slurry from spray nozzles at four separate levels (three plus a spare) to absorb $SO_2$. At the bottom of the absorber, the recycle slurry disengages from the flue gas and collects in the absorber reaction tank. The flue gas passes to the countercurrent section where it is contacted with recycle slurry from spray nozzles at three separate levels (two plus a spare) for residual $SO_2$ absorption. The flue gas then passes through the two stage mist eliminators to remove entrained water droplets before discharge to the new wet chimney.

To accommodate boiler startup operations, the scrubber can be bypassed through a bypass flue in the new chimney. Inlet dampers are provided to isolate the absorbers during bypass operation. Since all the flues are completely separate, outlet isolation dampers are not required.

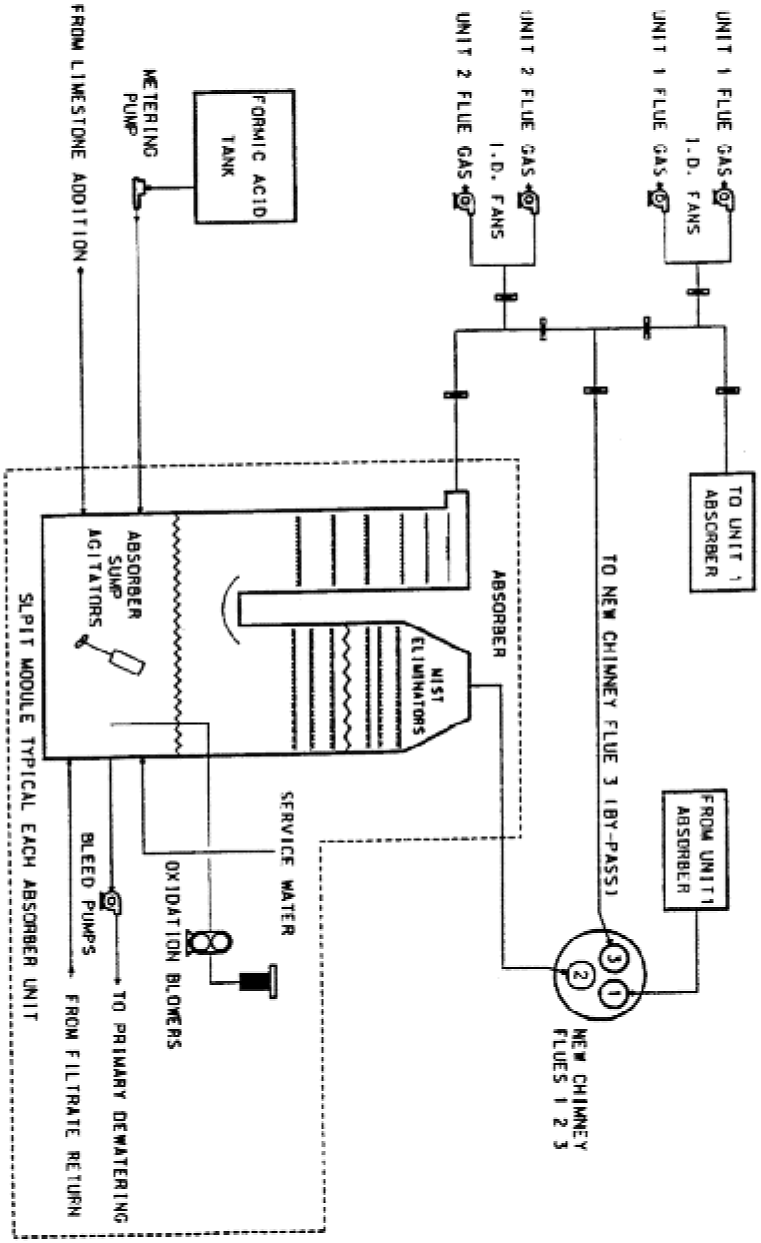
The MCCTD provided the first demonstration of the SHU process installed directly beneath a plant exhaust stack. This design approach saved considerable site space and would be of considerable benefit for existing plants where space for retrofitting an FGD is often at a premium. While the below-stack application of SHU technology was new, a related application, at the 230 MW Völklingen power plant in West Germany, houses the SHU absorber and auxiliary equipment inside a cooling tower. The Völklingen installation has been operating reliably since 1982.

### $SO_2$ Absorption

Recycle slurry from the absorber reaction tank containing formic acid is continuously pumped to the absorber spray nozzles by recycle pumps to provide the medium for $SO_2$ absorption. Each spray level (four cocurrent and three countercurrent) has one dedicated pump. The system is designed to meet 95% $SO_2$ removal efficiency when firing 3.2% sulfur coal at design flue gas rates, with only five of the seven pumps in operation. The pumps operate at constant flow. For turndown operation, individual pumps can be taken off line to meet the reduced slurry flow requirement. Six of seven recycle pumps in service and formic acid are required to achieve 98% $SO_2$ removal. Without formic acid, all seven spray levels and finer limestone grinding (90% minus 325 mesh) are required to achieve 95% removal efficiency.

# FIGURE 2.1-5

# SHU FLOW DIAGRAM



### Limestone Delivery, Preparation, and Addition

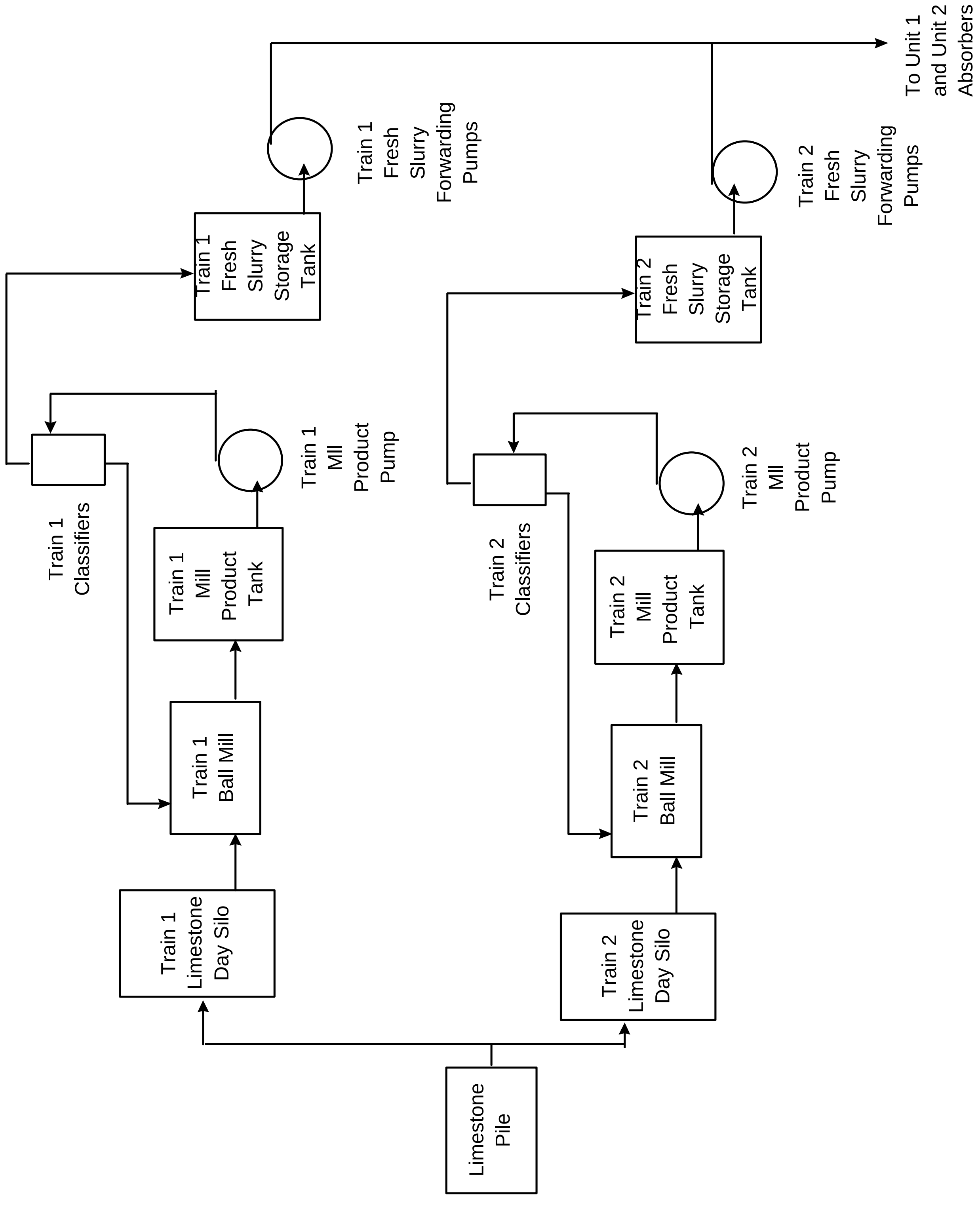
The SHU process uses limestone as the primary reagent for $SO_2$ absorption. Common facilities were provided for limestone unloading, storage, and reclaiming. Refer to figure 2.1-6. Limestone grinding, fresh slurry storage, and fresh slurry transfer are located in the limestone preparation area of the FGD building. The SHU process, when operating with formic acid, requires limestone to be ground to 90% passing 170 mesh, while a finer grind size, 325 mesh, is required when operating without formic acid. The limestone grinding facilities are capable of producing both of these limestone grind sizes.

Limestone from storage is conveyed to either of two 24 hour capacity storage silos (based on 3.2% sulfur coal at 110% of the plant maximum continuous rating (MCR)). Limestone is discharged from the bottom of a silo onto an individual weigh feeder and conveyed to a horizontal wet ball mill for size reduction. Clarified water (recycled process water) is supplied to the mills for grinding and dilution. The limestone slurry flows through the ball mill to the mill product tank. The mill product pump feeds the slurry to the cyclone classifier. Cyclone classifier underflow is returned to the ball mill. The limestone slurry product, at approximately 25% solids slurry, flows by gravity from the cyclone classifier overflow launder to the fresh slurry feed tank.

Limestone slurry is continuously pumped from the fresh slurry feed tank by the fresh slurry pumps to the absorbers. Slurry not required by the absorbers flows back to the fresh slurry feed tank in a complete loop. Limestone slurry addition to each absorber is regulated by a control valve in the take-off line to the absorber. The fresh slurry feed pumps are sized for two times required flow at design conditions and operate at constant flow.

## FIGURE 2.1-6

## LIMESTONE PREPARATION FLOW DIAGRAM



## Gypsum Production

Unlike many competing processes that produce gypsum, SHU byproduct gypsum is of excellent and consistent quality regardless of the plant load level or flue gas sulfur concentration. The gypsum was sold as 8% moisture gypsum powder for transportation to the purchaser.

The recycle slurry from both cocurrent and countercurrent absorber sections collects in the absorber reaction tank. The reaction tank acts as a back-mixed reactor to oxidize the product of absorption (bisulfite) to calcium sulfate (gypsum). Air is injected by oxidation air blowers. Side-mounted agitators are installed to provide complete mixing of air and slurry and to prevent gypsum particles from settling to the bottom.

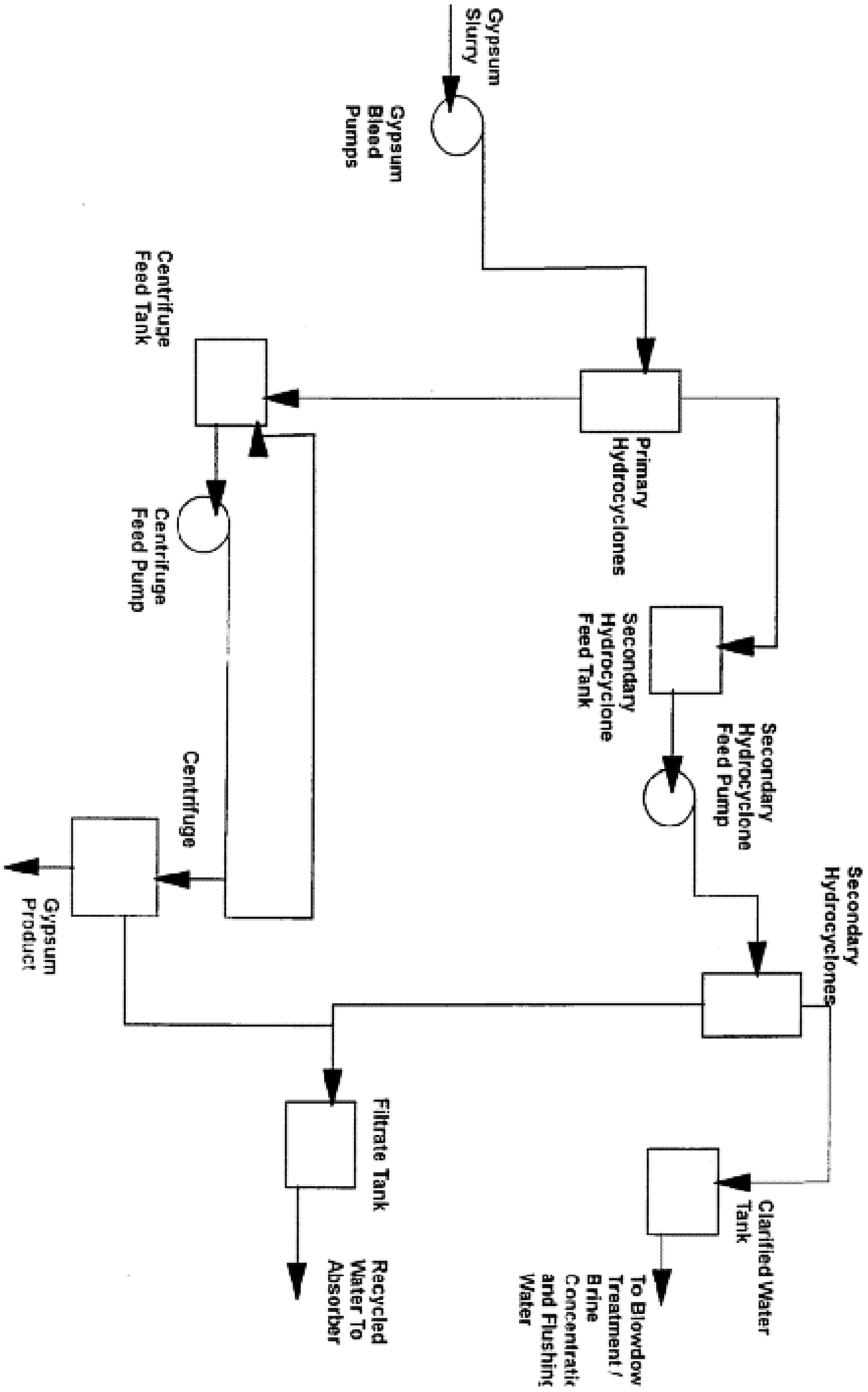
Oxidation also occurs in the absorber from excess oxygen in the flue gas. Slurry in the reaction tank contains approximately 10% gypsum, which provides seed crystals for the formation of gypsum particles. This eliminates uncontrolled gypsum growth on absorber internals (gypsum scaling).

Gypsum slurry (approximately 10% $CaSO_4 \cdot 2H_2O$) is pumped from the absorber sump by the bleed pumps to the dewatering area, located adjacent to the absorber area. Refer to figure 2.1-7. This area contains primary and secondary hydrocyclones, centrifuges and associated tanks and pumps. The slurry is concentrated to approximately 25 percent solids (later modified to 45% solids) in the primary hydrocyclones. The concentrated slurry collects in the hydrocyclone underflow launder and flows by gravity to one of the centrifuge feed tanks. The concentrated slurry is dewatered by the centrifuges producing a gypsum cake that is 92 percent solids by weight. A total of four centrifuges are provided for the two absorber modules including one spare for the 3.2% S case. Fresh process water is used to wash dissolved solids from the gypsum before the cake is discharged from the centrifuges. The cake is then conveyed by the transfer and forwarding conveyors to a storage building. The gypsum is stored until it is loaded onto trucks for transportation to the purchaser. Water decanted from the centrifuges is collected in the filtrate tank.

Overflow slurry from the primary hydrocyclones is collected in the hydrocyclone overflow launder and flows by gravity to the secondary hydrocyclone feed tank. The secondary hydrocyclone feed pump forwards a portion of the overflow slurry (enough to provide water for limestone preparation and for control of the concentration of chlorides in the absorber circuit) to the secondary hydrocyclones. The balance of the primary hydrocyclone overflow slurry overflows the secondary hydrocyclone feed tank and is collected in the filtrate tank. Underflow from the secondary hydrocyclones flows by gravity through an underflow launder to the filtrate tank. Clarified water (the overflow from the secondary hydrocyclones) flows by gravity to the clarified water tank. A small portion of the clarified water from the clarified water tank is pumped to the FGD blowdown treatment system. The balance is pumped to the limestone grinding system for reagent preparation.

## FIGURE 2.1-7

## BYPRODUCT DEWATERING FLOW DIAGRAM



### FGD Blowdown Treatment

One of the goals of the project was to demonstrate that the SHU FGD system does not necessarily generate additional plant wastewater. Wallboard grade gypsum and calcium chloride brine solution were produced as marketable byproducts. Virtually 100% removal of chloride from the flue gas is accomplished in the combination cocurrent / countercurrent absorber. The brine concentration system can allow the SHU blowdown stream to be purified and recycled to the plant as FGD make-up water. The calcium chloride produced from the brine concentration system, a commercially marketable product, can be sold as a brine solution.

A portion of the secondary hydrocyclone overflow stream is processed by the FGD blowdown treatment system to control the concentration of chloride ion in the absorber circuit. Refer to figure 2.1-8. FGD blowdown is chemically treated to promote coagulation, flocculation, and sedimentation of suspended solids and metals. Reject solids are dewatered via a plate and frame filter press. The chemically treated and clarified water can be discharged or further treated by a brine concentration system. Prior to processing in the brine concentrator, water is treated to adjust pH and remove dissolved gases. 90% of the feed to the brine concentrator is recovered as condensate (distilled water) which is returned to the FGD system as makeup water. The remaining 10% of the water is a brine that is highly concentrated in calcium, magnesium, sodium and chlorides and can be sold commercially.

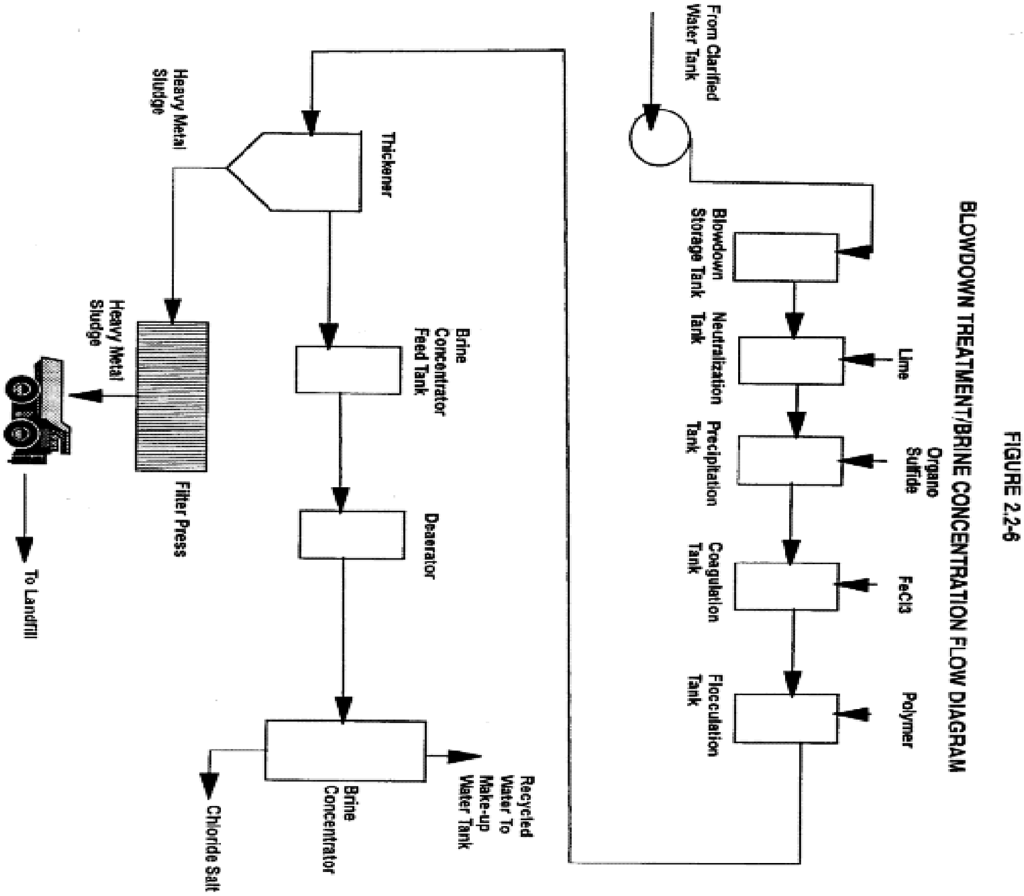
The energy efficiency of the brine concentrator is enhanced through use of a vapor recovery system and heat exchangers. Steam is required only for brine concentrator cold startup. During normal operation, no steam input is required. This results in an energy efficient zero wastewater discharge system which enhances the environmental attractiveness of the MCCTD project.

Blowdown from the clarified water tank is delivered to the blowdown treatment system's equalization tank from which it is fed to the pH elevation/desaturation tank where the pH is increased to a range of 11.0 to 11.2 by addition of lime to neutralize any mineral acids in the wastewater and initiate precipitation of magnesium, aluminum and iron. The wastewater then flows by gravity to the heavy metals precipitation tank where an organosulfide precipitation agent is added to provide a bonding median to which the precipitated metal molecules in the wastewater will adhere or join together forming a mass large enough to settle out of the stream. The wastewater then flows by gravity to the coagulation tank where ferric chloride, a mineral coagulation agent, is added. The wastewater then flows by gravity to the Densadeg® thickener system.

The Densadeg® thickener provides sufficient retention volume to allow settling of particulate from the wastewater stream. The thickener overflow normally flows by gravity to the brine concentrator storage tank or, if pH is too low or turbidity is too high, back to the equalization tank for retreatment. Polymer flocculant is added to the thickener's reaction tank to aid settling. Precipitated solids are collected by scrapers in the bottom of the thickener. This sludge is pumped to two locations. A dilute fraction taken from the region just above the sludge bed is recycled to the pH elevation/saturation tank to provide gypsum seed crystals to control system scaling. The balance of the sludge is routed to the sludge holding tank.

After lime is added, the sludge is pumped to a plate and frame filter press for dewatering. The lime aids in dewatering, allowing a drier cake to be formed. The cake from the filter press is collected in a dumpster for transport to an approved landfill for disposal. The filtrate returns by gravity to the wastewater equalization tank.

**FIGURE 2.1-8**
**BLOWDOWN TREATMENT/ BRINE CONCENTRATION FLOW DIAGRAM**



The brine concentration system accepts treated overflow from the Densadeg® Thickener and produces a concentrated brine solution which can marketed and a distillate which is recycled to the FGD system as process makeup water. Refer to figure 2.1-9.

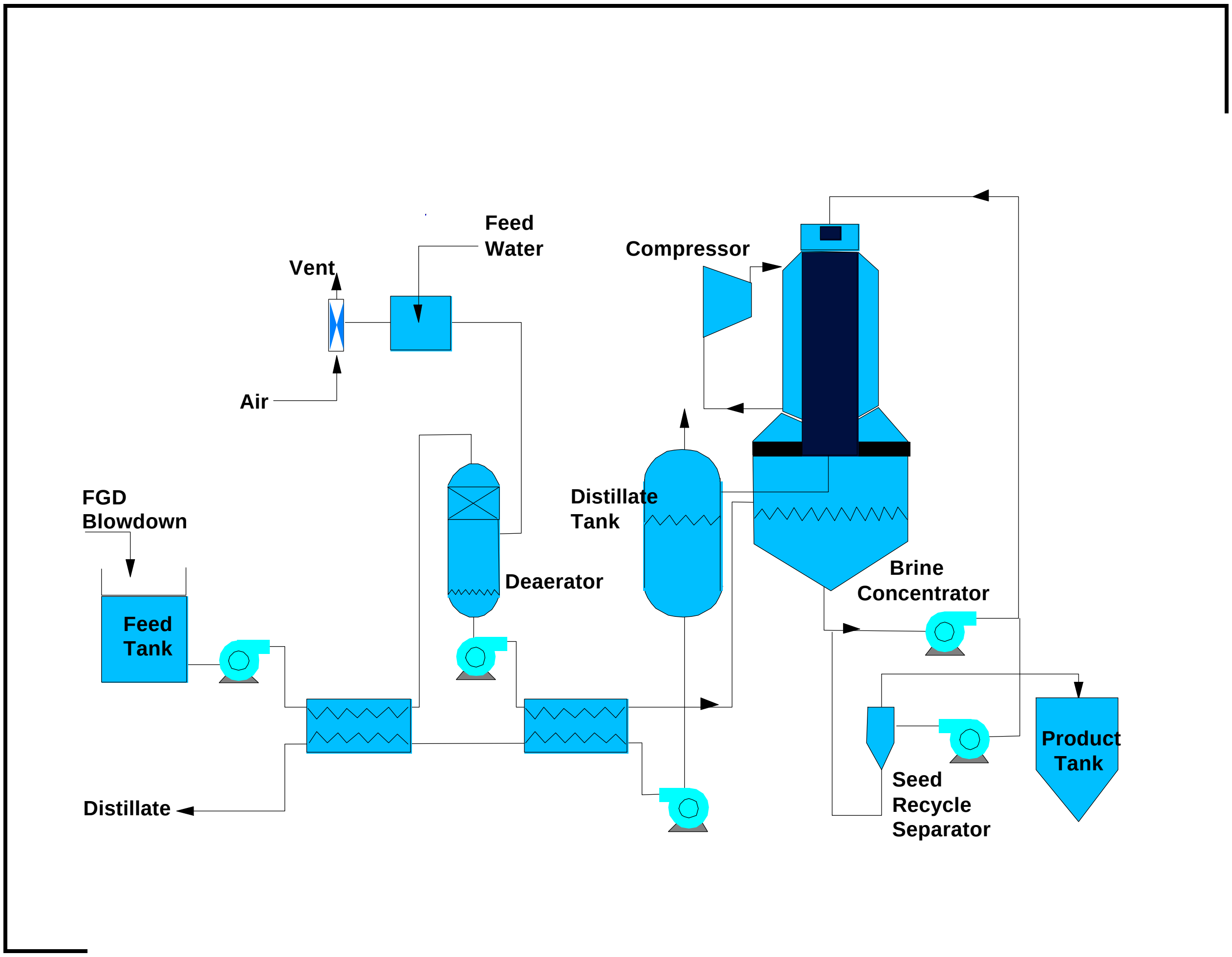
As originally configured the brine concentrator feed stream was conditioned with sulfuric acid and scale inhibitor in the feed tank and then pumped to the primary heat exchanger where it is heated to 150 $^{o}$F by the counter-flowing distillate stream. During startup sulfuric acid addition was replaced by hydrochloric acid addition to minimize the risk of forming calcium sulfate scale in the heat exchangers. A side stream is pumped to the barometric condenser to condense vapors drawn from the deaerator and is returned to the feed tank. The heated feed stream then enters the deaerator for removal of non-condensable gasses. The deaerated feed stream is further heated to near boiling in the secondary heat exchanger, again by counter-flowing distillate, and is then discharged into the brine concentrator sump where it mixes with recirculating concentrated brine slurry. Non-condensable gases released in the deaerator are pulled into the barometric condenser where the steam is condensed and the gases are vented to atmosphere.

The brine concentrator is a vapor compression type thin film evaporator consisting of a shell and tube heat exchanger (condenser) with a flood box over the upper tube sheet. The condenser is mounted over an integral sump. Concentrated brine slurry is pumped from the brine concentrator sump to the evaporator flood box where a nozzle sprays the brine through a strainer and floods the upper tube sheet. The brine slurry then flows down the inner walls of the condenser tubes as a thin film and falls back into the sump. The strainer funnels the larger particles into a separate tube that empties into the sump. The larger particles are eventually reduced in size by the recirculation in the system. As the thin film flows down the tube walls, the brine is heated to the boiling point. Steam from the heated brine flows down the centers of the tubes into the sump. The steam is drawn from the sump through mist eliminator pads by the vapor compressor. The vapor compressor raises the saturation temperature of the steam to above the boiling point of the recirculating brine. The steam is then introduced to the condenser where it gives up its heat of vaporization to the evaporating brine. The steam condenses on the outside of the tube walls, collects in the distillate tank and is pumped through the secondary and primary heat exchangers to the process water tank. Non-condensable gases that collect in the condenser are swept with low pressure steam through a baffle arrangement to the top of the distillate tank and then vented to atmosphere.

As the recirculating brine concentrates, calcium chloride begins to precipitate. To control scaling of the tube walls gypsum seed crystal are added to the recirculating brine solution. The brine concentrator uses a dual stream waste design. A side stream of recirculating brine is pumped from the sump to the seed hydrocyclone. The hydrocyclone underflow slurry is returned to the sump. A portion of the hydrocyclone overflow is discharged to the product tank as required to control dissolved solids concentration. A second stream is drawn from the sump to control the suspended solids concentration. This second stream is pumped to the product tank. In the product tank the suspended solids settle to the conical bottom and are pumped to the sludge holding tank for processing by the filter press. Overflow from the product tank, the concentrated brine by-product, flows by gravity to the brine storage tank.

FIGURE 2.1-9

BRINE CONCENTRATOR FLOW DIAGRAM



## Makeup Water

The SHU FGD process and its auxiliaries require service water for mist eliminator washing, absorber wall wash to prevent buildup at the wet/dry interface, quenching to cool the gas prior to absorption, and for washing the by-product gypsum cake. Additional service water as required to maintain system water balance is added to the absorber reaction tanks. Water for these services is distributed from the process water tank. The primary source of makeup water to the process water tank is the Process Water Reclamation Facility (PWRF), Milliken Station's pre-existing wastewater treatment system. The backup water supply is the power plant's house service water system.

## Slurry Drain System

For protection of the slurry lines against solid deposition when not in use, each slurry piping system is equipped with piping and motorized valves to automatically drain the slurry to the flushing sumps and flush the lines with clarified water. When recycle pumps are shut down, the main recirculation headers are drained to the flushing sump, then filled with clarified water. The drain valve is then reopened and the header drained to flush solids from the header and recycle pump.

Drain sumps are provided at the absorber to collect slurry flushed from the slurry lines. This slurry is then pumped into the absorber reaction tanks.

An absorber slurry drain tank is provided to collect and store the contents of an absorber reaction tank during emergency shutdown or scheduled outage when absorber inspection is required. This slurry is pumped back to the absorber as slurry makeup before restart of the FGD unit. Housekeeping trenches, sumps and pumps are provided in the reagent preparation, and gypsum dewatering area to collect material from floor washing. This material is pumped to the absorbers.

## FGD CONTROL PHILOSOPHY

An effective control system with proven reliability is provided for the SHU system. Some of the main control loops are summarized below.

### Controlling The Preparation of the Limestone Slurry

Limestone from the limestone silo discharges to a variable speed belt weigh feeder. The limestone is discharged from the weigh feeder to a wet ball mill. Clarified water from the gypsum dewatering system is added to the ball mill for grinding in proportion to the rate at which limestone is fed to the ball mill. Clarified water is also added to the mill product tank as required to maintain the density of the slurry fed to the limestone classifier.

### Control Of Limestone Addition

The fresh slurry forwarding pumps operate continuously to circulate limestone slurry in a loop from the fresh slurry storage tank to the absorber area and back. A take-off line from the main loop is located adjacent to each absorber and contains the limestone addition control valves. The rate of limestone addition to the absorber reaction tank is controlled by a feed forward control system. A flue gas flow rate signal from the boiler is multiplied by the $SO_2$ concentration in the untreated flue gas to create a signal proportional to total $SO_2$ mass flow to the absorber. Limestone slurry from the fresh slurry tank is added to the absorber in direct proportion to this $SO_2$ mass flow, by regulating the limestone slurry control valve. A limestone slurry density signal is fed to controller to compensate for any variation in the slurry density. The recycle slurry pH provides secondary control of limestone addition if the pH exceeds a specific range.

### Formic Acid Addition

Formic acid is added to the absorber reaction tanks using variable capacity piston pumps. Pump capacity is set manually based on laboratory analyses to maintain the desired formic acid concentration in the reaction tank.

### Emergency Water System

To protect the absorber internals from temperature excursion in the event of loss of power, an emergency water deluge system is provided. Water is supplied to this system from the plant's fire protection system. Temperature sensors are located inside the absorber below the second cocurrent recycle spray elevation. If high temperature is detected by these sensors a block valve automatically opens, admitting water to the emergency deluge sprays located near the top of the cocurrent section of the absorber.

### Quench Water

Makeup water is sprayed into the flue gas entering the absorber to cool the gas to reduce formic acid consumption and to prevent damage to absorber internals. As originally configured the flow of process water to the quench sprays was controlled to maintain flue gas temperature as measured by sensors inside the absorber above the first cocurrent spray elevation. This modulating control scheme was changed to on/off control during startup due to erratic flue gas temperature signals.

### Wall Wash Water Sprays

Whenever the absorber is on line makeup water is sprayed onto the absorber walls in the upper portion of the cocurrent section to prevent build-up of solids at the wet/dry interface. A pressure control valve maintains a constant wash water flow rate.

### Mist Eliminator Wash Sprays

Each absorber module is equipped with two mist eliminator stages which are located above the last absorber recycle spray bank. The first stage mist eliminator removes most of the entrained moisture from the flue gas. The second stage removes the finer mist particles which penetrate the first stage. The mist eliminator wash system provides online cleaning by spraying the mist eliminators with makeup water. The wash system includes four sets of wash water headers. One set washes the bottom face of the first stage mist eliminator; the second set washes the top face of the first stage; the third and fourths sets wash the bottom and top faces of the second stage, respectively. Each set of wash water headers includes several individual headers, each with a dedicated wash isolation valve. The wash water control system opens and closes the individual wash isolation valves according to a preprogrammed sequence. The program ensures that the amount of wash water used is within system water balance limits and concentrates washing in the areas most susceptible to solids buildup. A pressure control station maintains a preset wash water supply pressure.

### Oxidation Air

A constant amount of compressed air is injected into the absorber reaction tank through air lances located adjacent to the absorber agitators to oxidize bisulfite ions to sulfate. Vendor-proprietary control logic implemented in the distributed control system (DCS) controls the air compressor inlet guide vane position for optimum compressor efficiency. Makeup water is injected into the air supply header to saturate and cool the air prior to injection in order to prevent formation of "wet/dry" buildup and consequent air lance plugging. A pressure control valve maintains constant water pressure to the air quench spray nozzle.

### Control of Recycle Pumps

The recycle pumps run continuously without control on throughput. The pumps are taken out of service or placed on line at the operator's discretion to suit the load condition.

### Gypsum Bleed and Dewatering

The gypsum bleed and dewatering system removes gypsum solids from the FGD system, maintaining the suspended solids concentration in the absorber reaction tank within a preset range. Slurry from the absorber reaction tank is continuously transferred to the gypsum dewatering system by the bleed pumps. Density of the reaction tank slurry is sensed in the bleed pump discharge line. The primary hydrocyclones separate the slurry into two fractions, the underflow which contains approximately 25% solids (increased to 45% solids during startup) and the overflow which contains about 3% solids. The underflow fraction flows by gravity to the centrifuge feed tank. The overflow fraction is collected in the secondary hydrocyclone feed tank. Centrifuges are provided to process the underflow, producing clean gypsum cake for export and a filtrate stream which is collected in the filtrate tank and recycled to the absorber reaction tank. Centrifuge feed pumps continuously circulate the underflow from the centrifuge feed tank past each centrifuge and back into the feed tank. While the density of the bleed slurry rises from its low set point to its high set point, the centrifuge feed tank overflows to the filtrate tank, returning the suspended solids to the absorber. When the density reaches its high set point (nominally 12% solids), the centrifuges begin dewatering the concentrated slurry, causing the density of the bleed slurry to fall. Dewatering continues until the low density set point is reached. The centrifuges are then stopped and the centrifuge feed tank is again allowed to overflow, returning the gypsum solids to the absorber. The absorber bleed slurry density then begins to rise and the cycle is repeated.

The centrifuges are controlled in accordance with a pre-programmed six step batch cycle through the DCS: FEED, SPIN 1, WASH, SPIN 2, PEEL, CLEAN. Five of the six steps occur each cycle. The sixth step, CLEAN, occurs only every fourth cycle. The duration of each step in the cycle is preprogrammed and can be customized through the DCS. During the FEED step the centrifuge is accelerated to FEED speed and the centrifuge's two feed valves open, admitting slurry from the continuously circulating feed loop into the machine. At the conclusion of the FEED step the feed valves close and the SPIN 1 step begins. During this step the centrifuge continues to spin at the FEED speed, removing most of the liquor from the gypsum. After the SPIN 1 step times out the centrifuge continues to spin at the FEED speed and the WASH step begins. During this step makeup water is sprayed onto the gypsum cake to displace absorber process liquor and its associated dissolved solids residue. After the WASH step is concluded the centrifuge continues to spin at the same speed for the duration of the SPIN 2 step as the cake achieves its final dryness. This is followed by the PEEL step during which the centrifuge brakes to the PEEL speed, the discharge chute moves to the conveyor position and the cake knife removes the gypsum from the centrifuge basket. Normally the centrifuge moves to the FEED step at the end of the PEEL step. Every fourth cycle, however, the CLEAN step starts at the conclusion of the PEEL step. The CLEAN step also precedes centrifuge shut down. The CLEAN step has two phases, HEEL RINSE and BASKET WASH. During HEEL RINSE the heel rinse valve opens flushing residual gypsum cake from the centrifuge. After the HEEL RINSE is complete the basket wash valve opens, cleaning the centrifuge basket. Throughout the CLEAN step the centrifuge continues to rotate at the PEEL speed.

As mentioned above, the overflow fraction from the primary hydrocyclones is collected in the secondary hydrocyclone feed tank. A portion of this stream overflows from the feed tank to the filtrate tank and is recycled to the absorber. The balance of the primary hydrocyclone overflow is processed by the secondary hydrocyclones to produce clarified water for use in limestone slurry preparation, system flushing and for system blowdown. The secondary hydrocyclone underflow is collected in the filtrate tank for recycle to the absorber.

### 2.1.3 STEBBINS TILE ABSORBER CONSTRUCTION

An additional feature demonstrated for the FGD market was the use of a tile-lined, split module absorber provided by the Stebbins Engineering and Manufacturing Company located in Watertown, New York. The absorber is a concrete vessel with tile lining and a common center dividing wall to provide each unit with its own absorber module. Each side of the vessel operates independently of the other. This unique concept provides greater operating flexibility and reliability to the plant. The split module allows the flue gas from each boiler to be independently treated at a lower capital cost than would be required for the construction of two separate vessels. The tile lining promised superior abrasion and corrosion resistance when compared to rubber and alloy linings and is expected to last the life of the plant. In addition, because the tile-lined concrete construction method requires minimal construction access, it is ideal for use in retrofit projects, where space for construction is often at a premium. The use of Stebbins tile for absorbers in a split cocurrent / countercurrent module is being pioneered at Milliken Station to demonstrate the many competitive advantages of the tile system as an alternative FGD absorber construction technique.

#### REINFORCED CONCRETE TILE-LINED CONSTRUCTION

Corrosion of the absorber is a problem that has plagued the FGD industry from the earliest installations. Reinforced concrete/tile construction offers a cost effective alternative to conventional absorber construction materials by offering enhanced resistance to corrosion and associated improvements in reliability and availability. The tile should be unaffected by the process for the life of the plant.

Reinforced concrete / Stebbins SEMPLATE® ceramic tile construction offers the following potential advantages compared to conventional scrubber designs and materials of construction:

- superior corrosion and abrasion resistance.
- high reliability and availability.
- suitability to construction in a congested area.
- on-line repairs.
- ability to withstand higher temperature or temperature excursions.

The exterior walls of the absorber vessel are constructed of various thicknesses of carbon steel reinforced concrete walls with ES block exterior, SEMPLATE® tile interior and SEMPLATE® tile coping at top. Interior walls are constructed of various thicknesses of carbon steel reinforced concrete with SEMPLATE® tile on both sides and SEMPLATE® tile coping at the top. Interior walls include the common wall of the split module and the cocurrent / countercurrent separation baffle. The tile is not bonded to the absorber walls, but is mechanically anchored to the concrete core. Acid brick is used instead of tile as the interior lining in the hot gas inlet zone. The floors of the split module are constructed of carbon steel reinforced concrete floor fill, lined with grouted SEMPLATE® tile. All interior joints are fully grouted with AR-196 chemically resistant mortar cements.

ES insulating blocks form the outside wall face to minimize the thermal gradient and resulting stresses. Lightweight block was specified to meet minimum strength requirement with various materials used depending upon local sources. Wall thickness is adjusted to meet structural requirements with one or more mats of reinforcing steel specified. The bottom ten feet of the vessel exterior are lined with SEMPLATE® instead of block as a house-keeping consideration.

Carbon steel reinforced concrete SEMPLATE® tile support corbels and embedded alloy clips are provided for internal support of spray piping mist eliminators and turning vanes.

Piping penetrations above the recycle slurry sump liquid level are constructed of flanged carbon steel nozzles set in the structural wall with FRP inserts set solidly in AR-196 chemically resistant mortar cement. Penetrations below the liquid level and in the hot inlet gas zone are constructed of solid alloy set in the structural wall.

## CONSTRUCTION METHOD NEEDS LITTLE SITE SPACE

Because the individual building components are small, an absorber can be constructed of reinforced concrete/Stebbins tile in a more congested area, compared to the area needed for conventional scrubber construction.

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 site area burden.

## RELIABILITY IS HIGH, AND LIFECYCLE COST LOW

The use of Stebbins tile will increase reliability; the tiles are expected to last the life of the plant. Only the integrity of the mortar need be of limited concern for maintenance. The tile/mortar system is designed to expand after start-up, ensuring that the tile is in compression and the mortar joints are very tight. This nearly eliminates potential for tile cracking. It also reduces lining permeability, insuring the concrete core will be well protected. The mortar used in this design is a silica filled vinyl ester which is expected to be slowly attacked by the process and to require "repointing" after 15 to 20 years of operation. Since the mortar is slightly permeable, the absorber contents eventually come into contact with the concrete core in some localized areas. Due to the low permeability of the mortar, the permeate is not continually replenished and the minor chemical attack on the surface of the concrete should not affect the structural integrity of the concrete core to any significant degree over the life of the plant. Minor leakage, however, may occur through minute stress cracking in the tile/mortar system. A leak would present itself on the outside of the concrete wall as a damp spot. Since a leak would allow the contents of the absorber to continually be replenished within the concrete core, degradation would occur at the area of leakage. Due to the high alkaline reserve in Stebbins concrete mix, structural damage may not occur for several years.

Should leaks develop, Stebbins has a unique process whereby they can be repaired with the unit on-line thereby offering the potential for very high system availability. Leaks can be stopped during operation or shutdown by drilling small holes in the area of the leaks to a depth of approximately 2", installing a 1/4" PVC nipple and pumping a catalyzed epoxy resin or a colloid into the affected area. This mixture solidifies along the path of the leak forming an effective and permanent plug. Once leakage is stopped, concrete attack also stops.

The tile and mortar system is inspected annually from the access openings and every three years from a "pick" or boatswain's chair. Inspection of the concrete is done periodically through visual inspections for leaks. In addition, Stebbins recommends that core samples of the concrete be taken at random locations every five years. Cores can be taken to within 2" of the back of the tile during operation and will not damage the integrity of the absorber wall.

The reinforcing steel would not come in contact with the absorber contents unless there were leaks. However, if leakage were to occur repair by pumping, resin or colloid, as previously described, would be undertaken, which would eliminate any potential corrosion problem.

The reliability of the tile and mortar system is expected to be superior to any other material for absorber construction. Lifecycle costs associated with the use of the tile and mortar lining system are expected to be substantially lower than those of either a steel alloy absorber or a carbon steel absorber lined with chlorobutyl rubber or flake glass linings. 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.

Maintenance during outages should be less with the proposed Stebbins tile absorbers than other types of absorbers. This is because of the superior low-maintenance characteristics afforded by the structural and mechanical properties of the Stebbins tile.

## PRIOR SUCCESS OF THE TILE AND MORTAR SYSTEM

The Stebbins tile and mortar system is used with high success in the chemical process industry in chemical environments which are much more hostile than in an FGD system. The Stebbins tile and mortar system has only been used over reinforced concrete in one other utility scrubber, an M.W. Kellogg horizontal weir scrubber installed at the D.B. Wilson Generating Station. However, the application used here is substantially different from that used in the Kellogg unit. The Kellogg design is for horizontal gas flow whereas the Milliken absorber has vertical, cocurrent / countercurrent, gas flow. Therefore, the Milliken absorber is much taller and has an internal wall to create two separate modules. D.B. Wilson Generating Station has three operating modules with one spare, while Milliken will have a single split module absorber (forming two operationally independent halves for each unit) with no spare. The reliability demand for Milliken Station is much greater. The SHU process operates at a lower pH, formic acid enhanced, higher chloride environment than the Kellogg process, making this a harsher test of the tile system. The Milliken project demonstrates the applicability of Stebbins ceramic SEMPLATE® tile construction to a more corrosive environment.

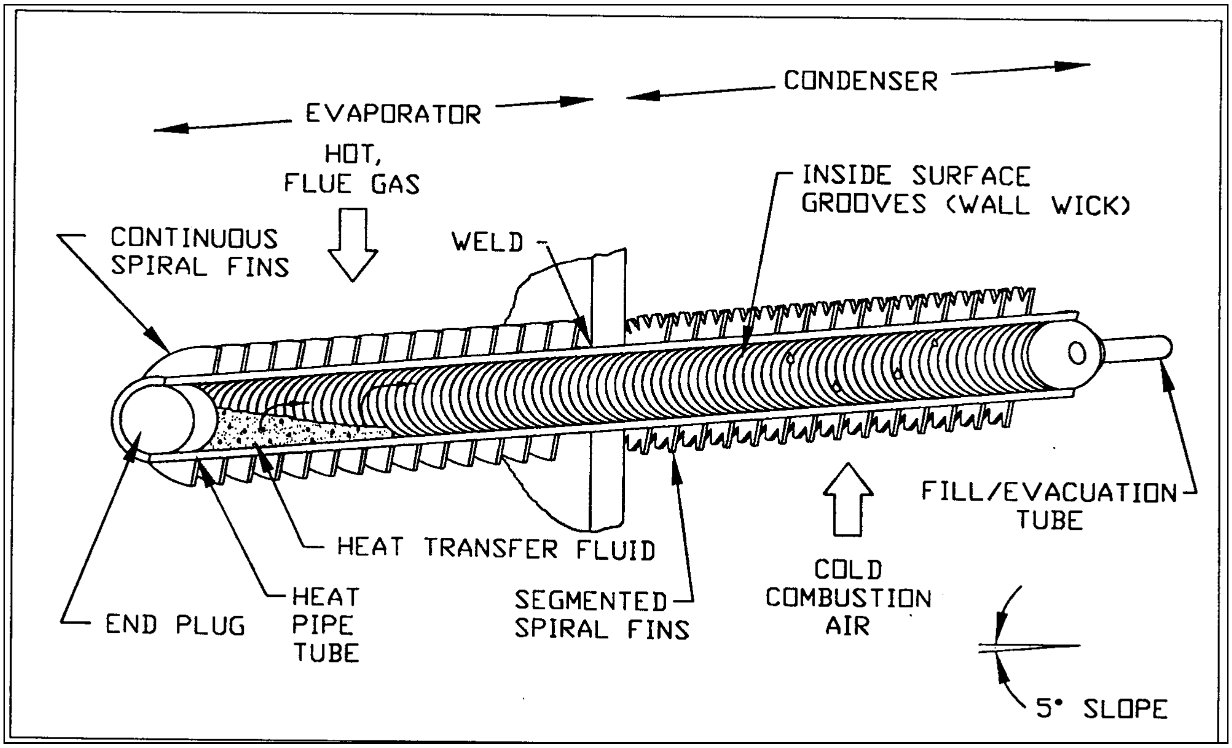
### 2.1.4 ABB AIR-PREHEATER, INC. HEAT PIPE AIR HEATER SYSTEM

An important feature of the MCCTD project is the demonstration of the energy savings provided by a heat pipe air heater installation on a utility boiler. The Milliken Station Unit 2 Ljungstrom® regenerative type air heater was replaced with a heat pipe air heater system supplied by ABB Air-Preheater, Inc.

#### GENERAL DESCRIPTION HEAT PIPE AIR HEATERS

The heat pipe is a new heat exchanger design which can be used for utility air heaters. The heat pipe design has the potential to eliminate many of the problems associated with the tubular and Ljungstrom® air heater designs and to operate at somewhat lower flue gas outlet temperatures which would improve overall plant heat rates. Heat pipe air heaters operate as regenerative exchangers in which heat from the hot flue gases is indirectly transferred to the cold air by means of a working fluid. The operation is illustrated in figure 2.1-10. The heat pipe tubes are partially filled with a heat transfer working fluid. The heat pipe tube is sealed under high vacuum to insure that the only gas inside the tube is the working fluid vapor. Passing hot flue gases over the lower end of the tube causes the working fluid to boil and the vapors to flow to the cold end of the tube. Cold air flowing over the top of the tube condenses the vapors releasing latent heat which heats the air. Since the heat pipes are mounted at a slight angle from horizontal ($5^o$ for the Milliken units), the condensed liquid flows by gravity back to the evaporator end of the pipe to repeat the cycle. Wall grooves or wicks are sometimes used inside the heat pipe tubes to improve wall wetting and heat transfer.

**FIGURE 2.1-10**
**HEAT PIPE CROSS SECTION**



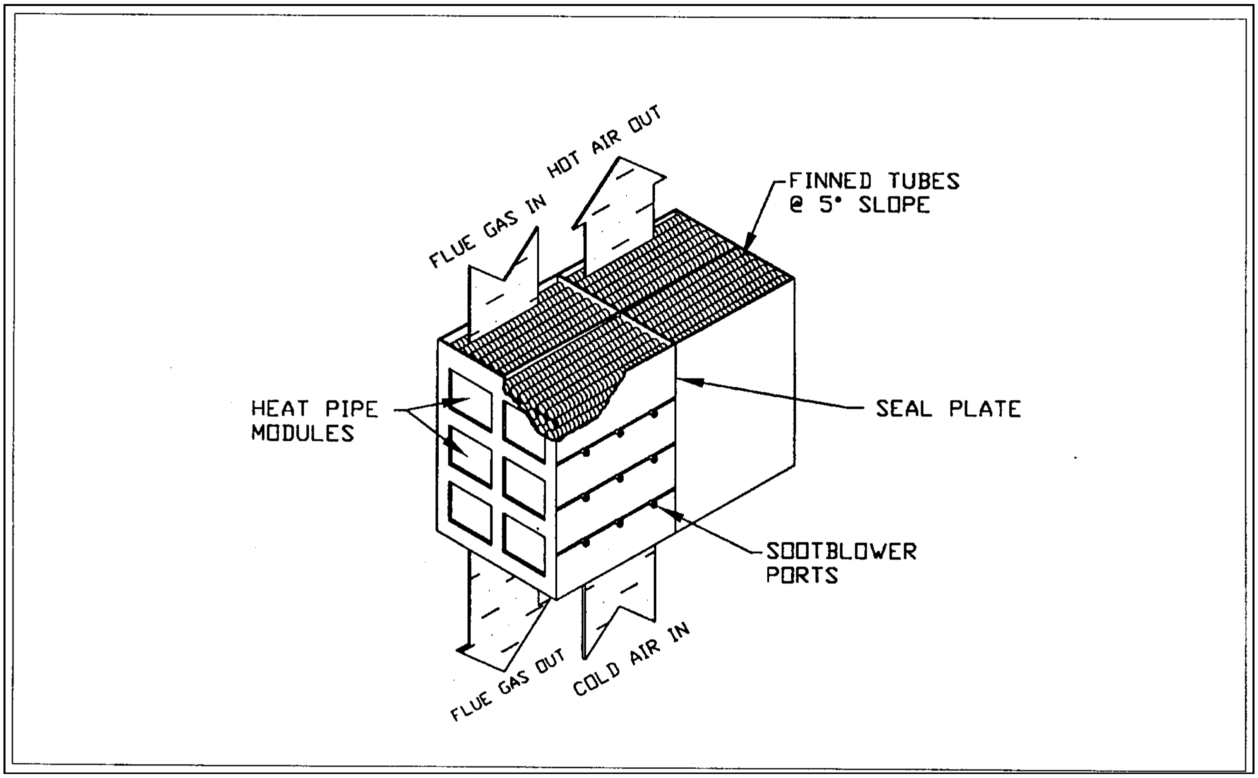
Inside a heat pipe, heat is transferred by boiling and condensing heat transfer mechanisms. For these mechanisms, heat transfer can proceed at extremely high rates as compared to conduction and/or convection. Because of this, a heat pipe can transfer several thousand times the amount of heat energy as solid copper for a given temperature difference. Due to the high internal heat transfer rates, individual heat pipes operate essentially isothermally with very small temperature differences between the hot and cold ends. This aids in achieving uniform outlet temperatures for heated and cooled process streams.

Depending upon the application, many different materials can be used as working fluids including: liquefied gases, water, hydrocarbons, chlorofluorocarbons, and liquid metals. The working fluid must be operated below its critical temperature, must be compatible with the tube wall material, and must be stable and not decompose under operating conditions. For the Milliken air heater design, naphthalene was selected for the high temperature sections and toluene used in the intermediate and cold end sections.

A full-scale heat pipe air heater consist basically of two ducts with a common wall. Individual heat pipe tubes extend through the common wall across both ducts (figure 2.1-11). Hot flue gases flow through one duct while cold combustion air flows through the other duct. The tubes are usually seal welded or gasketed in some fashion at the common wall to prevent air leakage between the flue gas and air sections. The ends of the tubes are free to expand or contract as necessary within the duct casing. By extending the individual tube surface through the use of fins, compact units can be designed.

## FIGURE 2.1-11

## TYPICAL HEAT PIPE AIR HEATER CONSTRUCTION



The main advantages of the heat pipe air heater design over tubular designs are: compactness, a lower potential for air leak development, and uniform temperature distribution across the heat transfer zone. The common wall divider between the flue gas and air sections is made of a thick, heavy metal plate which is unlikely to corrode through over the life of the unit. Additionally, each heat pipe tube provides a double barrier against air leakage. Should a tube become penetrated on the flue gas side due to corrosion, the tube would loose the charge of working fluid and become inactive. Air would not however flow into the flue gas section unless the air end of the tube also became punctured, an unlikely event. Finally, because each heat pipe operates isothermally along its length, the outlet temperatures for both the heated and cooled streams can be controlled more exactly and uniformly. This potentially could benefit utility air heaters by eliminating flue gas side cold spot areas and allowing operation at lower outlet temperatures due to tighter control of the cold-end heat transfer surface metal temperatures.

The heat pipe is an innovative replacement option for the Ljungstrom® air heater. Installation of a heat pipe provides energy savings in two ways. First, air leakage across the air heater is eliminated, reducing the volume of flue gas that must be handled by the FD and ID fans resulting in lower fan power consumption and increased boiler thermal efficiency (since more heat is transferred to the combustion air). Second, the heat pipe maintains a more uniform exit gas temperature thereby allowing operation at lower average exit gas temperatures while maintaining a safe margin above the acid dew point. It has been estimated that for every 35 °F reduction in average flue gas exit temperature, plant efficiency increases by approximately one percent, a strong incentive for heat pipe air heater installation.

When compared with the Ljungstrom® type regenerative air heaters, actual and potential advantages of the heat pipe design are:

- Zero air leakage
- Better outlet temperature control allowing for more heat recovery and lower flue gas Outlet temperatures
- Passive design with no moving parts
- Lower erosion due to low flue gas velocities
- Lower flue gas and air side pressure drops
- Potential for improved ESP operation due to more uniform flue gas exit temperature profile.

### CAPCIS CORROSION MONITORING SYSTEM

The MCCTD project planned to demonstrate the use of the CAPCIS corrosion monitoring system in conjunction with one of the heat pipe air heaters. Each air heater has an integral, air-side bypass duct with an electric motor-actuated damper for cold end corrosion protection. The damper opens to allow combustion air to bypass the air heater in order to prevent the temperature of the flue gas from falling below the acid dewpoint. The CAPCIS system includes a number of sensors installed at strategic locations in the flue gas stream, the exit channels of the electrostatic precipitators, the air heater cold end section and at the outlet of the induced draft fans. At each location, the following variables were to be sensed:

- Electrochemical Impedance
- Electrochemical Potential Noise
- Electrochemical Current Noise
- Temperature

The outputs from these sensors were to be processed in a programmable logic controller (PLC) and compared with pre-defined electro-chemical parameters (set points) to control the position of the air heater bypass damper. Set points characterizing the threshold for onset of material corrosion were to be determined during the demonstration. When the corrosion rate got too high, the control damper would modulate open, reducing the heat load and increasing the flue gas exit temperature. In this manner the system would adjust the flue gas exit temperature to the lowest temperature consistent with corrosion prevention.

The project intended to demonstrate the energy efficiency and conservation gains achievable by incorporating this total system to maximize the thermal efficiency of the boiler while preventing corrosion. Unfortunately, software problems were encountered with the CAPCIS system during the demonstration which were not resolved at the time of publication of this report.

### 2.1.5 NALCO FUELTECH NOxOUT® SELECTIVE NON-CATALYTIC REDUCTION

As originally configured the MCCTD project included combustion modifications for primary $NO_X$ emissions control and Nalco Fuel Tech's NOxOUT® selective non-catalytic reduction system (SNCR) to further reduce $NO_X$ emissions while retaining flyash salability. The SNCR system was to be demonstrated on only one of the units at Milliken Station (Unit 2) while combustion modifications were installed on both units, thus demonstrating the process's capability for incremental $NO_X$ emissions reductions beyond that achievable through combustion modifications alone. The site of the NOxOUT® demonstration was ultimately relocated to GPU's Seward Station which is not equipped with low $NO_X$ burners. This change limited the scope of the demonstration to the evaluation of the capabilities of the NOxOUT® process as a standalone $NO_X$ reduction technology.

The NOxOUT® process provides reduction in $NO_X$ through reaction with urea injected into the post-combustion zones of the boiler. The NOxOUT® system is a very energy efficient and low capital cost approach to controlling the emissions of nitrogen oxides produced in the combustion process.

## ANALYTICAL $NO_X$ COMPUTER MODELING

Before a NOxOUT® system is installed, the process feasibility is determined through computer modeling of the gas phase chemical kinetics, flue gas dynamics, heat transfer and particle momentum dynamics. Process performance is analyzed using Nalco Fuel Tech's chemical kinetics computer model (CKM). Process conditions are evaluated using computational fluid dynamics (CFD) modeling techniques. The CFD modeling enables the simulation of injector design configurations to evaluate the effectiveness of urea dispersion in the flue gas, providing the necessary design information for location and number of injection points. Used together, the CKM and CFD models provide a sound basis for predicting expected performance.

## EQUIPMENT DESIGN BASE

The process equipment designs incorporate experience from demonstration and commercial applications to oil and gas fired boilers. Control hardware and software are specified and designed to enable the NOxOUT® process to compensate for load changes. The degree of $NO_X$ removal can be customized for each application. Automatic feed control and monitoring software systems can also be provided.

## NOxOUT® AS AN EMISSION CONTROL DEMONSTRATION

Prior to the MCCTD project SNCR processes using urea injection had achieved 30 to 60% reduction in $NO_X$ emissions on a full-scale, commercial, oil-fired utility boilers. The MCCTD project extends the application of this technology to utility-scale high sulfur coal-fired boilers in the United States. The MCCTD project originally intended to demonstrate the overall effectiveness of the NOxOUT® system in coordination with other boiler upgrades including combustion modifications, a coordinated plant control system, and a burner management system.

The incorporation of all these state-of-the-art features would have permitted the demonstration of several criteria including:

- Minimum 30 percent additional $NO_X$ reductions beyond that achievable with combustion modifications alone

- Improved cost effectiveness for $NO_X$ reduction

- Evaluation of effects of simultaneous operation of the $NO_X$ reduction technologies on air heater, ESP, scrubber operations and fly ash quality.

The relocation of the demonstration to Seward Station, which is not equipped with upstream $NO_X$ control technology or an FGD system, required modifying these objectives to some extent. NOxOUT® was evaluated as a standalone technology, as opposed to a technology in combination with combustion control upgrades. The demonstration identified maximum achievable $NO_x$ reductions using NOxOUT® as a standalone technology while maintaining marketable fly ash. During periods of low fly ash sales (e.g., winter months) the maximum $NO_x$ reduction while maintaining less than 5 ppm of ammonia slip was demonstrated. The effects of NOxOUT® on air heater and ESP operations and fly ash quality were evaluated, but not its effects on scrubber operation.

This full-scale, long term demonstration provides answers to such utility industry issues as long term $NO_x$ emission rates, boiler-related impacts, operating and maintenance costs, effects on downstream equipment (air preheater, ESP) performance and the effects on sales potential of byproducts (fly ash). The scale (150MW) and duration of testing should be sufficient to resolve these concerns.

Demonstrating the removal efficiency of the NOxOUT® process in a utility boiler fired with high sulfur coal was designed to allow the NOxOUT® system to be evaluated with respect to the applicability to either a retrofit application or a new installation. At an equivalent $NO_X$ emission rate, the MCCTD project was able to demonstrate the ability of the NOxOUT® process to mitigate the adverse effects normally inherent with a single technology, including:

- ammonia slip with NOxOUT®,

- carbon carry-over with combustion modifications, and

- waterwall slagging with combustion modifications.

The control of these effects is critical for utilities, like NYSEG, that are dedicated to maximizing the utilization and sale of byproducts, such as fly ash and gypsum. Excessive amounts of either ammonia slip or carbon carry-over would contaminate the fly ash collected in the electrostatic precipitators and prevent the continued sale of the fly ash. Fly ash sales are used by utility companies to reduce landfill requirements. Loss of these sales would greatly increase the landfill requirements for the fly ash, which would be detrimental to the overall environmental goals of the US.

## HOW THE NOxOUT® SNCR PROCESS OPERATES

From 1976 to 1981, research sponsored by the Electric Power Research Institute (EPRI) established that urea was an effective agent to convert $NO_X$ into harmless nitrogen, carbon dioxide, and water via these reactions.

$$\mathbf{2NO + NH_2CONH_2 + 1/2\ O_2 \rightarrow 2N_2 + CO_2 + 2H_2O}$$

$$\mathbf{2NO_2 + 2NH_2CONH_2 + O_2 \rightarrow 3N_2 + 2CO_2 + 4H_2O}$$

These reactions take place only in a narrow temperature range, 1600 °F to 2100 °F, below which ammonia ($NH_3$) is formed, and above which $NO_X$ emission levels actually increase.

The NOxOUT® process uses a mixture of urea and patented chemical enhancers together with mechanical modifications to widen the temperature range over which the basic urea injection process is effective and to control the formation of ammonia. The development of specialized chemical formulations for the NOxOUT® process has increased the level of $NO_X$ reduction as compared to urea injection. These formulations are carefully controlled to ensure the proper enhancer/urea (E/U) ratio and include proprietary additives to prevent problems such as injector fouling.

The E/U ratio is one of the most significant process variables in the NOxOUT® process. As noted above, the E/U ratio can effect the amount of $NO_X$ reduction achievable. The E/U ratio controls the formation of ammonia. Ammonia is formed as an undesirable side reaction which is accelerated as the flue gas temperature decreases or as the $NO_X$ reduction level is increased. Ammonia production is generally undesirable because of the possibility of forming ammonium sulfate and ammonium bisulfate in the presence of sulfur trioxide. Ammonium bisulfate has been known to cause fouling in the air preheater.

Through the development of the enhancers and optimization of E/U ratios, advances in the process chemistry have been realized. In addition, controlled multiple level staging of the injection points in the different temperature zones of the boiler is often possible. Multiple staging of injection points increases the $NO_X$ reduction while maintaining low ammonia slip.

## PROCESS DESCRIPTION

The NOxOUT® process, provided by Nalco Fuel Tech, achieves $NO_X$ reduction by the reaction of $NO_X$ with urea injected into the post-combustion zones of the boiler. The urea is injected as an aqueous solution. The quantity of water used for dilution is typically set by the requirement to achieve a good distribution. The urea solution contained in storage normally contains 50% by weight of urea. This solution is then diluted on-line to the concentration for injection which may be in the range of 5 to 20% by weight of urea. In order to avoid scaling of the injectors and to avoid the need for water of high purity for dilution, an anti-scaling additive is used. This permits the use of ordinary service water for dilution. This anti-scalant combined with a dispersant for droplet size optimization is contained in the concentrated urea solution which is marketed under the trade name NOxOUT A®.

The most critical parameters in the design of a NOxOUT® injection system are gas temperature, residence time, carbon monoxide concentration of the gas at the point of injection, uncontrolled $NO_X$ concentration, amount of $NO_X$ reduction required and ability to distribute chemical at the appropriate combination of temperature and residence time. Carbon monoxide concentration is almost as important as temperature because it is a measure of the concentration of reactive species in the gas phase. The temperature window for reaction shifts to lower temperatures with increases in carbon monoxide concentration.

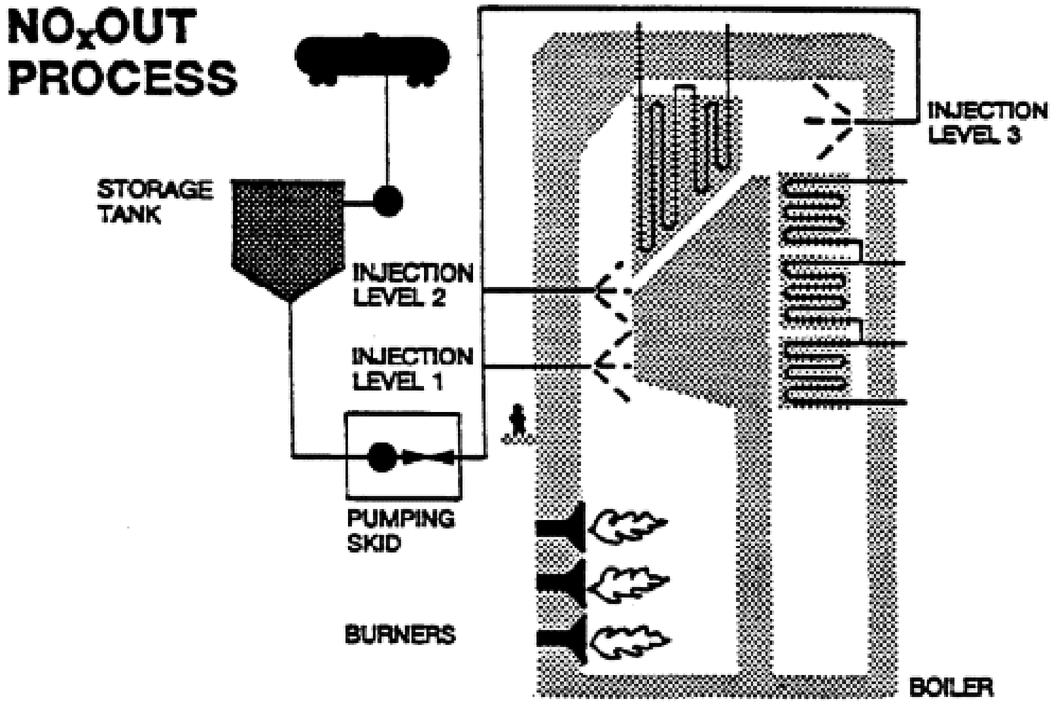
The first step in evaluating a potential application is a survey for gas temperature, carbon monoxide concentration and accessibility. This information is used in combination with other basic parameters such as fuel rate and excess air to construct a three dimensional, computational fluid dynamic (CFD) model of the boiler. The temperature-residence time profiles generated by this model are then used in a chemical kinetic model of the NOxOUT® process to predict the amount of $NO_X$ reduction and ammonia slip that can be expected under theoretical conditions. The output from the kinetic model is then recycled to the CFD model where chemical injection is simulated. This simulation permits selection of preferred injection locations and optimum parameters for injection. These parameters include average droplet size, droplet size distribution and droplet velocity. Preferred injectors for a specific application are then drawn from an array of injectors that have been previously characterized.

The equipment required to deliver the chemical to the injectors is designed based on the specific range of flow rates required, the nature of the control system desired, the amount of air required for atomization and any local construction codes. A modularized approach is used in which the overall delivery system is broken down into five specific segments: storage, recirculation, metering/mixing, distribution and injection. The NOxOUT® process includes:

- Proprietary computer codes to ensure that the NOxOUT® chemicals are optimally distributed in the boiler.
- Control hardware and software to enable the NOxOUT® process to follow boiler load changes by altering the flow rate and injection point of the urea-based reagents.
- Chemical feed, storage, mixing, metering, and pumping systems.

Figure 2.1-12 contains a typical schematic diagram of the NOxOUT® process.

## FIGURE 2.1-12
## NOxOUT® PROCESS



### 2.1.6 COMBUSTION MODIFICATIONS

The burners and control systems for both Unit 1 and Unit 2 boilers were modified to provide primary $NO_X$ reduction. These combustion modifications were an integral portion of the project as originally configured since they reduce $NO_X$ levels by about 20%, providing a more relevant baseline for evaluation of the downstream NOxOUT® demonstration. The downstream NOxOUT® demonstration was to be designed to work with this primary combustion system on Unit 2 to demonstrate low levels of $NO_X$ emissions. Ultimately the NOxOUT® portion of the demonstration was relocated to GPU's Seward Station.

### LOW NOX CONCENTRIC FIRING SYSTEM (LNCFS)

Combustion modifications were installed on both Milliken units for primary emission control. The modifications consisted of replacing the existing conventional tangential firing system with the Low $NO_X$ Concentric Firing System (LNCFS) furnished by ABB CE Services. The LNCFS maximizes the $NO_X$ reduction capabilities of existing tangential firing systems while minimizing unit modification. The LNCFS uses a combination of two techniques to reduce $NO_X$, bulk furnace staging and early controlled coal devolatilization.

Bulk furnace staging takes a portion of the combustion air, which is introduced at the fuel burning zone, and diverts it to retard air and fuel mixing. With conventional tangential firing, the introduction of excess combustion air during the early stages of coal devolatilization contributes significantly to the formation of $NO_X$. The LNCFS maximizes the bulk staging concept by using both overfire air and concentric firing. Staged combustion is produced by introducing a portion of the secondary air, called overfire air, above the primary firing zone. This is accomplished by utilizing a close- coupled overfire air system in which the overfire air nozzles are located in the top elevations of the main windboxes and a new, separate overfire air windbox, which is installed above the existing windbox. The concentric firing system utilizes a re-direction of the secondary (auxiliary) air which is admitted in the main firing zone, diverting it away from the coal stream. In this manner, combustion stoichiometry is reduced by preventing the fuel stream from entraining with the air stream during the initial stages of combustion. Fuel nitrogen conversion is reduced while maintaining appropriate oxidizing conditions along the furnace walls. The introduction of air in the concentric firing circle is accomplished with the installation of offset air nozzles.

Another important design feature incorporated into the LNCFS is the technique of early fuel ignition. Initiating the combustion point very close to the fuel nozzle produces a stable volatile matter flame which is more easily controlled under sub-stoichiometric firing conditions. A two-piece "flame attachment" type coal nozzle tip is used to promote this strong primary flame.

### PCGC-3 COMBUSTION MODEL

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 the 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 US 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 $NO_X$ reduction achieved through its use.

### 2.1.7 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 evaluate key data emissions parameters, such as $NO_X$, $SO_2$, $O_2$, CO, $CO_2$, 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.

In 1997, the project was modified from that described in the Public Design Report to make PEOA more user friendly, to include two other modules: Monitor and Advisor (developed from an earlier project), and to attach each module with open architecture. The entire package of three modules is called TOPAZ® and consists of the Monitor, Optimizer (i.e., PEOA) and Advisor. The Monitor archives and displays operating data and trends that data. The Advisor provides the logic behind the recommendations given by the Optimizer, and shows any problems with input data to TOPAZ® from the plant. The reason for this change is to make the Optimizer more commercially attractive by making it more user friendly and easily expandable by open architecture design.

TOPAZ® is being developed as an “Open”, client/server-based system using object-oriented development technologies. Developed in this manner, TOPAZ® will be capable of smoothly integrating with legacy power plant DCS, performance monitoring, and information systems on a variety of network topologies, operating systems, and hardware platforms. TOPAZ® system consists of three modules, each performing a separate function. Together the three modules make up a comprehensive system which not only monitors plant processes but also provides recommendations based on past data and industry practices. The Monitor provides acquisition, storage, and display of process data by interfacing with plant instrumentation and operators. Users can customize screens to tailor the system to their specific needs by building tables, trends and plots to display the available data.

The Optimizer employs artificial intelligence techniques to model the relationships between the operator’s actions and the earnings of the plant. This “plant model” is then used to recommend control settings for the lowest-cost operation. TOPAZ® evaluates major operational cost factors when searching for the plant’s optimal target state, including emissions, plant thermal performance, and waste management.

The Advisor guides the user through the actions that will bring the plant into its optimal state. The Advisor determines the best course of action by comparing actual data to optimized target data, and then applying heuristic rules based on expert knowledge about plant operation. The rules are both generic and unit specific, and incorporate knowledge regarding the 1990 Clean Air Act Amendment (CAAA) and corporate compliance strategies. The TOPAZ® knowledge bases incorporate expertise based on plant experience as “rules”, which are structured so that end-users can easily modify or customize the rules according to their changing needs. The Advisor also provides a means for detecting bad data values and identifying any calculations in which those values were used.

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 eliminate the need to upgrade or enhance existing systems that may already be adequate.

## THE MONITOR

The Monitor provides a convenient way of viewing and managing the vast amount of operating data available. The data are acquired by interfacing with existing systems, such as digital control systems, programmable logic controllers, and so on. The data are archived for later use, such as analyzing a unit trip or pinpointing operating problems. The Monitor is capable of archiving based on average values, such as hourly, daily, or shift averages for ease in analysis and comparison.

The data are displayed using the Plant Views feature, which provides a schematic of various systems and places the data at the appropriate location on the schematic. Trends and tables can be quickly built by “clicking-and-dragging” the data point from the plant view onto a trend window. The data can be viewed in a table format, and trend (time-based) format, or an X-Y plot to make correlation between operating parameters.

Other options exist to make the Monitor even more useful. The Performance Calculations option provides a complete set of power plant performance calculations based on ASME Power Test Codes. The calculations can be used in conjunction with the Monitor to continually monitor plant and system performance. The Data Playback option allows the user to load historical data and “play back” a certain event or series of events.

## THE OPTIMIZER

The Optimizer is at the heart of the TOPAZ® system, and is a mathematical model of the plant process. The plant model supplies the relationships between the model inputs (the independent parameters) and the model outputs (the dependent parameters). The cost function calculates the “bottom-line”, i.e., the cost per kWh generated. The foremost purpose of TOPAZ® is to help operators and engineers to minimize the cost function during normal operation, producing the highest possible earnings.

TOPAZ® views the process of economic optimization as several relatively distinct issues:

- Modeling the relationship between operator actions and system parameters that indicate plant efficiency, and determining the base set of operator controllable parameters to achieve the highest profits.

- Determining the relationship between plant performance parameters, factors external to the plant, and the overall profitability of the process.

- Recommending the best set of operator actions to achieve optimal operation.

The plant model incorporates the constraining mathematical relationships between plant parameters. There are several modeling methods which are used in TOPAZ®:

- Empirical relationships created with TOPAZ®'s Historical Target Generator (HTG™) software. The HTG™ system creates constraints of the form $y_1 = f(x_1, x_2, x_3)$, where $y_1$ is the dependent variable, and $\{x_i\}$ are the independent variables. HTG™ uses empirical data gathered automatically while TOPAZ® is on-line.

- Equations based on the physics of the problem, such as mass and energy balances. For example, equations of the form $x_1 + x_2 + \ldots = y_1 + y_2 + \ldots$

- Empirical relationships generated by an artificial neural network (ANN).

Neural networks provide an attractive approach for developing constraint relationships for several reasons:

- They provide accurate representations of complex, non-linear relationships, based on training from real-world, empirical data.

- They are relatively inexpensive to build and port between applications, since they can be implemented with "generic" paradigms, and are trained from empirical data.

- They require a less detailed understanding of the physical processes they represent, especially the associated complex interdependencies and non-linearities.

The TOPAZ® architecture can implement one of several different ANN paradigms, including backpropagation. The backpropagation ANN (BPNN) is based on a multi-layered (i.e., at least three), fully connected architecture. BPNN's can be trained to map input values (mathematically represented in vectors) into output values (vectors). During this ANN training process, the weights and biases of the ANN's "neurons" and "synapses" (i.e., connections represented mathematically by matrices) are adjusted to minimize the sum squared error of the network. BPNN process models developed by DHR converge virtually instantaneously and are well suited to the multi-input/output modeling capabilities required for the TOPAZ® plant model.

TOPAZ®'s Optimizer uses the plant model to determine the best set of controllable parameters for optimal economic operation. Conceptually, the Optimizer performs two steps:

- Identify the set of all plant model input/output vectors that satisfy the plant model constraint equations.

- Determine which input vector minimizes the cost function. This vector represents the optimal solution to the problem.

TOPAZ® also includes a "what-if" feature that provides interactive access to the models, allowing users to test the impact of various operating scenarios on plant economic performance.

TOPAZ®'s cost function considers both cost and income factors. The cost factors are divided into two basic categories: (1) raw materials costs, and (2) waste disposal costs. Income factors are also divided into two basic categories: (3) electricity sales, and (4) waste product sales. In addition, there are certain constraints (e.g., $NO_X$ limits, load requirements) that apply, and at least one miscellaneous item ($SO_2$ credits), that can significantly impact either cost or income. These constraints depend on the particular process (e.g., power plant) to which TOPAZ® is applied, and the associated CAAA corporate compliance strategy.

TOPAZ® presents the overall cost of operating the plant as fuel cost, which is calculated from heat rate, plus other costs (e.g., bottom ash disposal), minus other income (e.g., fly ash sales). The advantage to this approach is that it presents cost in a format often used by the industry. However, this approach does not provide feedback that is directly attributable to a single plant activity. The cost function equation for this approach is:

$$C_{ttl} = C_{fuel} + C_{other} - I_{other} \qquad \text{(all in units of mills/kWh)}$$

where:

$C_{ttl}$ = total coast of operating the plant

$C_{fuel}$ = fuel cost, obtained by multiplying net station heat rate by fuel price

$C_{other}$ = non-fuel raw material costs (e.g., urea, limestone) and waste disposal costs (e.g., bottom ash disposal) integrated on an hourly basis, summed, and then divided by the same hour's power output to obtain unit of mills/kWh.

$I_{other}$ = income from byproduct sales (e.g., gypsum, flyash), integrated on an hourly basis, and then divided by the same hour's power output to obtain unit of mills/kWh.

## THE ADVISOR

The Advisor helps operators interpret the recommendations provided by the Optimizer. The Operations Advisor provides heuristic (rule of thumb) advice and explanations that supplement the recommendations from the Optimizer. The heuristic knowledge is based on the operational expertise of experience plant operators and engineers, plus it incorporates 1990 CAAA compliance strategies. The Advisor incorporates three types of functionality:

- Prioritizes the order of operator actions. The Operations Advisor examines differences between actual data and optimized target data to identify which actions will have the greatest impact on plant economics. Also, since the optimal target state is dynamic (i.e., each operator action changes the state of the plant)., the Operations Advisor provides advice that considers the impact of plant dynamics.

- Provides detailed descriptions and explanations of detected problems. The Operations Advisor provides background information about the nature of problems occurring in the plant to help operators gain a better understanding of plant physics and operations, as well as CAAA emissions control strategies.

- Provides a control strategy for controllable parameters that do not map directly to DCS Commands. Certain parameters, such as boiler cleanliness factors, do not map directly to DCS controllable parameters. For example, if the Operations Advisor finds that both the primary superheater and secondary superheater cleanliness factors are low, it knows that both cleanliness factors are affected by certain sootblower batches. The Operations Advisor first checks the state of other boiler surfaces which are also affected by those batches and searches for the "least common denominator" that will provide the best overall result. If no other boiler surfaces require cleaning, then the Operations Advisor recommends using specific retractable sootblowers that will provide the most benefit to the primary and secondary superheaters.

The Advisor also provides an "intelligent alarms" feature using rules similar to those shown above. This will notify the users of any suspect data points and identify all calculations in which those data points were used. It can also be used to examine a calculated value to determine all of the data points which are used in the calculations.

## 2.2 DESCRIPTION OF DEMONSTRATION FACILITIES

### 2.2.1 INTRODUCTION

This section of the Project Performance and Economics Report briefly describes the overall demonstration facility as it existed at the end of the project and identifies new and retrofit elements of the process equipment. The reader should refer to the Public Design Report and to Section 3.0 of this report for more detailed information.

### 2.2.2 THE HOST FACILITY

The Milliken Clean Coal Technology Demonstration Project was installed at NYSEG's Milliken Station, historically one of the 20 most efficient generating stations in the United States. The demonstration facilities of the Milliken Coal Technology Demonstration Project provided the capabilities for significant reductions in emissions of sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_X$) while simultaneously minimizing the heat rate penalties typically resulting from the application of pollution control technologies.

Milliken Station is located on the east shore of Cayuga Lake in Lansing, New York, approximately 12 miles northwest of Ithaca. There are two Combustion Engineering pulverized coal-fired units, Units 1&2, at Milliken Station, each rated at a nominal 150 MW. The balanced draft units are tangentially fired with four elevations of burners at each of the four corners. The plant is about 40 years old.

Cayuga Lake is approximately 39 miles long, varying in width between 1 and 3 miles with a maximum depth of 435 feet. At the site, the lake width is approximately 1.75 miles, with a normal elevation of approximately 382 feet (msl). In the immediate vicinity of the plant, the terrain rises from the lake shore to an elevation of about 800 feet (msl). Within 3 miles east of the plant, the terrain rises to about 1100 feet (msl). From this region out to 50 miles or more, the terrain generally ranges above 1000 feet (msl) with widely scattered high points between 2000 and 3000 feet (msl). The terrain west of Cayuga Lake is generally similar to that east of the site. Other glaciated valleys similar to that of Cayuga Lake exist west and northeast of the site, forming the other Finger Lakes. The area surrounding the plant up to one mile from the site boundary consists of mostly cropland and lake, with forest and forest brushland making up the next largest classification. It is sparsely populated with no major population centers.

The general climate in the central New York Finger Lakes region is dominated by polar continental air masses tracking from the north and west. Frequent invasions of air masses from the Gulf of Mexico result in rapid variations of weather conditions. The regional climate is characterized by long, cold winters and cool summers with occasional warm, humid periods. Precipitation is evenly distributed throughout the year.

Seismic activity in the region of the site is low. Previous research showed that earthquakes in the northeastern United States are infrequent. The earthquakes that do occur in the northeastern United States are usually of shallow focus and characterized by low magnitude and/or intensity.

The site holds all the prerequisites to demonstrate this technology, such as access, water, rail transport, roadways, electric power, labor force, coal supply and other required utilities.

The site holds several significant advantages to the demonstration. Milliken Units 1 and 2 have, over the years, proven to be two of the most efficient and reliable units in the nation. This proven track record ensured that the demonstration would proceed smoothly according to schedule on units that had to operate to meet load demands. Units 1 and 2 are base loaded units, assuring a good demonstration and providing the opportunity for potential users to observe the technologies in commercial operation. The selection of such an efficient plant underscored the demonstration project team's commitment to achieve high $SO_2$ removal efficiency with minimal FGD energy consumption.

Milliken Station Units 1 and 2 are two comparably sized boilers. This feature was key to the development of this project. It allowed demonstration of the split module absorber concept and, at the same time, permitted independent operation of the SHU process on each boiler unit. Operation of identical absorbers at independently variable conditions allowed process data to be more fully verified and facilitated identification and analysis of abnormalities, either process or physical, as they occurred.

The site is an operating power plant with all the facilities necessary to demonstrate this technology, such as access to water, rail transport, roadways, electric power, labor force, coal supply, and other utilities as required. Cayuga Lake provides an abundant source of water which is used for all plant needs. The relatively small amount of makeup water required for the FGD system did not require additional water withdrawal from the lake. Railroad access was available on site to meet the requirements for coal deliveries to the station and for delivery of equipment and construction materials. All electric power requirements for both the construction and operational phases of the project were easily met from Milliken Station. FGD power was provided by a new substation constructed on the power plant site. Construction labor force was available through the Ithaca Building and Construction Trades Council which has as members craftsmen from all required trades, including carpenters, iron workers, laborers, plumbers and electricians. The operating force was readily supplied from current NYSEG employees at the power plant and from the labor force of the surrounding area. Eastern US coal was the major source of fuel supply. The site accommodates coal delivery via both truck and rail. The majority of coal is delivered by rail. All other utilities such as potable water and sewage treatment were provided by the pre-existing power plant resources.

Though Milliken was previously in compliance with all air quality emission standards, changes due to the 1990 Clean Air Act Amendments (CAAA) required more stringent control of air emissions. The installation of the advanced FGD and $NO_x$ control systems with this project ensured that Milliken Station will meet or exceed all current and all newly imposed CAAA $SO_2$ and $NO_x$ requirements. The most significant improvement is in $SO_2$ emissions, which are reduced by about 90% on an annual basis (95% $SO_2$ removal, 95% FGD reliability).

The location of the site in the Finger Lakes region of New York State makes this plant a contributor to acid rain deposition in the Adirondack and the Catskill Mountains. Completion of the project on this site provides environmental benefits to these important natural resources. Due to Milliken's location in New York State, transboundary emissions to Canada are theoretically reduced.

The plant's location in a scenic area raised local concerns about the site's appropriateness for a technology demonstration. However, NYSEG found the surrounding communities as a whole to be supportive of the project due to its many environmental benefits. NYSEG, committed to an active community contact program, began making public contacts prior to project award to inform officials and concerned citizens about plans and address their questions. Initial contacts were favorable and continued throughout the project.

Milliken's proven operating history, its access to water, transportation, road, power, labor and fuel resources, and its proximity to the Adirondack and Catskill Mountains and Canada made it an excellent site for a Clean Coal Demonstration Project.

### 2.2.3 THE FGD PLANT

The centerpiece of the demonstration facility is the FGD plant which is located in a new building along the lake shore about 100 feet north of Unit 2. The FGD building, a custom-designed steel structure enclosed by insulated, galvanized steel siding, has an el-shaped footprint measuring 21,000 sq.ft. and a roof line reaching 184 ft. above grade. The roof-supported steel chimney shell rises another 141 feet. Three chimney flues protrude another 50 feet above the top of the chimney, for a total height of 375 feet above grade. The building houses most of the equipment associated with the FGD process including the absorbers, the absorber recycle pumps, the oxidation air blowers, the gypsum dewatering hydrocyclones and centrifuges, the limestone day silos and wet grinding equipment, the FGD blowdown pretreatment and brine concentration equipment and the process makeup water tank and pumps. The building also houses the FGD Control Room, the FGD electrical equipment rooms and the FGD process laboratory. The building is provided with steam heat. The control and electrical equipment rooms are air conditioned. A personnel elevator provides access to all operating floors. An elevated walkway provides access from the Unit 2 building at the control room level.

Elevated ducts carry flue gas to the FGD building from the Unit 1 and Unit 2 replacement ID fans which are located just west of their respective ESP's. Limestone is delivered to the plant by truck and stored outdoors on the elevated plain about 300 feet northwest of the FGD Building. Byproduct gypsum is stored in an unheated building immediately to the north of the FGD Building. Tubular belt conveyors connect the limestone receiving hopper and the gypsum storage building to the FGD building. The absorber slurry drain tank, a cylindrical concrete vessel provided for temporary storage of absorber scrubbing solution, sits immediately to the east of the FGD building.

## LIMESTONE HANDLING

Limestone is delivered to the site by truck and stored in an outdoor pile. Space is allotted on site for a three-month inventory. As required to meet process demand, front- end loaders reclaim limestone from the storage pile and load it into the 35 ton capacity unloading/reclaim hopper. The hopper can also receive limestone directly from the delivery trucks. The hopper is equipped with a 6-in by 6-in "grizzley" screen, bin heaters to prevent the limestone from freezing and an electric motor-actuated FMC "Pin-Rak" dewatering slide gate. The limestone is withdrawn from the hopper by a 24-in wide by 48-in long variable speed FMC/Syntrom Vibrating Feeder at a rate of 50-100 tons per hour. The feeder is equipped with a DCE insertable dust collector to reduce fugitive dust emissions as limestone is discharged onto a 24-in wide, 100 tons per hour capacity belt conveyor for transfer to the limestone day bins in the FGD Building.

The 370-ft long belt conveyor is fully enclosed in an 8-ft diameter structural tube. The conveyor has a takeup tower at mid span and is equipped with a magnetic metal separator, a belt scale, speed controls, alignment and safety switches and gravity ventilators. Limestone is discharged from the conveyor into a discharge chute equipped with an electric motor-actuated diverting flop gate. The flop gate directs the limestone either directly into one of two storage bins or onto a 40-ft long belt-type transfer conveyor for charging the second storage bin. A DCE insertable dust collector controls fugitive emissions at the transfer points.

Each of the 24-ft diameter, 320 ton capacity storage bins is equipped with a DCE reverse jet fabric vent filter, level controls and a 12-ft diameter Kinergy vibrating bin discharger. Limestone flows to the limestone preparation system through a 2-ft diameter nozzle at the bottom of each bin's discharge cone.

The limestone handling system was designed and supplied by FMC's Material Handling Systems Division.

## LIMESTONE PREPARATION

The limestone preparation system produces the limestone slurry used for $SO_2$ removal in the absorber. The system consists of two independent trains, each designed to produce 24 tons per hour of limestone slurry. One limestone preparation train operating 12 hours per day can supply all the limestone slurry consumed by both absorber modules at design conditions. Each train includes an inlet slide gate and down spout, a weigh feeder, a mill feed chute, a ball charging hopper and chute, a ball mill with auxiliaries, a mill product tank with agitator, two classifier feed pumps, a mill hydrocyclone classifier assembly and a classifier distribution box.

At the heart of each limestone preparation system train is a 10-ft diameter by 20-ft, 6-in long Fuller Traylor ball mill. The mill consists of a horizontal steel cylinder with a replaceable 3-inch thick rubber liner with lifting bars, charged with 75 tons of hardened steel balls. The cylinder is supported between two ball and socket trunnion bearings with replaceable bronze inserts. The cylinder is rotated at 18.6 rpm through a split-ring type girth gear bolted to the shell flange on the feed end and through a pinion gear mounted to the mill sole plate. The pinion gear is driven through a drive train including a 900 hp/1200 rpm main drive motor, a Flender parallel shaft gear reducer and an Airflex clutch. An automatic spray lubrication system is provided for the girth and pinion gears. A hydrodynamic / single pocket hydrostatic lubrication package is provided for the trunnion bearings. The feed end of the mill has a rubber-lined fabricated steel trunnion liner with a forward-spiral slurry retention system and a rubber-lined steel spout feeder with a slurry retention splash plate. "O" ring seals are provided to prevent slurry leakage between the trunnion liner and the trunnion. The discharge end of the mill has a rubber-lined fabricated steel trunnion liner with a reverse spiral to return grinding media to the grinding chamber. The discharge head of the mill is fitted with a trommel screen with slotted openings. The screen has an advancing spiral to convey mill product to a rubber-lined discharge chute. Material too large to pass through the trommel screen openings is conveyed past the discharge chute to a rubber-lined rejects chute. Each mill has a jacking system consisting of a power unit with four 75 ton jacks and accessories. Two fabricated cradles are supplied of use in conjunction with the jacking system. Each mill also has an "inching" system consisting of a parallel shaft reducer and motor with brake mounted on a moveable base. A disengaging coupling connects the reducer to the mill. Mechanical and electrical interlocks prevent simultaneous operation of the inching drive and main mill drive motor.

Limestone is metered into each mill from its associated storage bin by a Stock Model 9024 NPG non-pressurized gravimetric feeder with electronic weighing and microprocessor controls designed to deliver 21.6 to 54 tons per hour. Limestone flows by gravity from the day storage bin through a motor-operated slide gate onto the weigh feeder belt. A leveling bar mounted downstream of the weigh feeder inlet shears the material column to form a profile conducive to maximum weighing accuracy. The rubber-covered, mechanically spliced belt has a counterweighted scraper with replaceable rubber blades to continuously clean the carrying surface of the belt after the limestone is discharged. A plow type scraper cleans the return strand of the belt downstream of the outlet. The weighfeeder has belt tensioning and belt tracking adjustments. The belt is driven by a 1.5 hp dc motor through a 200:1 reducing gearbox. The distributed control system (DCS) controls motor speed through a locally mounted dc motor speed controller. An ac tach generator attached to the motor provides speed feedback for the controller.

Dry limestone is discharged from the weigh feeder through a rubber-lined feed chute into the mill. Clarified water (recycled process liquor) is piped to the feed chute from the clarifier distribution box. The feed chute has a plugged chute probe. Grinding balls are added to the mill through a ball charging hopper and chute which discharge into the mill feed chute.

Crushed and slurried limestone discharges through the mill trommel screen into the 10-ft diameter x 10-ft tall rubber-lined mill product tank which is equipped with a Lightnin model 74QS7.5, 7.5 hp vertical agitator. Clarified water is also added to the tank to adjust the density of the slurry. Mill product pumps (1 operating and 1 spare) feed slurry from the product tank to the mill classifier assembly. The pumps are ASH Model 6 x 6 SRH #4 rubber-lined slurry pumps with BW RIS mechanical seals operating at 518 gpm and 100 ft TDH. The pumps are v-belt driven at 1260 rpm by an overhead mounted 50 hp motor. Robicon model ID-454 variable frequency drives provide pump speed adjustment to suit mill classifier process requirements.

The mill classifier assembly provided by Krebs Engineers has 5 Model DF6B-12$^{o}$-1766 hydrocyclones, 3 Model DSF10LB-1703 hydrocyclones, a rubber-lined feed manifold, rubber-lined underflow and overflow launders, a knifegate isolation valve for each hydrocyclone, a feed pressure gauge and a feed pressure transmitter. The model DF6B hydrocyclones are used to produce a mill product fineness of 90% through 325 mesh. At design conditions 4 hydrocyclones are on line and the fifth is a spare. The larger model DSF10LB hydrocyclones are used to produce the coarser 90% through 170 mesh mill product required when the FGD system is using formic acid. At design conditions 2 hydrocyclones are on line and the third is a spare. The hydrocyclones have rubber-lined FRP casings and adjustable rubber apexes.

The classifier overflow launder discharges through a flexible hose to any one of three compartments of the rubber-lined mill distribution box. One of these compartments is piped to the Unit 1 fresh slurry feed tank. A second compartment is piped to the Unit 2 fresh slurry feed tank. A third compartment is piped to the mill product tank. An air cylinder-actuated hose positioner directs the overflow to the desired compartment, based on programmed control logic.

The classifier underflow launder discharges through a flexible hose to either of two compartments of the mill distribution box. One of these compartments is piped to the mill feed chute. The second compartment is piped to the mill product tank. An air cylinder-actuated hose positioner directs the overflow to the desired compartment, based on programmed control logic.

## FRESH SLURRY ADDITION

The two fresh slurry feed tanks hold a combined 24-hr supply of properly classified limestone slurry for use by the FGD process. Each of the 64,000 gallon capacity, rubber-lined tanks has a Lightnin' model 75 QS5, 5 hp vertical agitator with rubber-covered shaft and impeller to keep the limestone solids in suspension. The 84-in diameter agitator impeller operates at 31 rpm.

A total of four horizontal, belt-driven, centrifugal fresh slurry forwarding pumps, two for each fresh slurry feed tank, supply fresh slurry to the absorber modules. One pump can supply 100% of the limestone slurry required by both absorber modules at design conditions. The pumps are ASH Model 5 x 4 SRH rubber lined slurry pumps with BW RIS mechanical seals operating at 550 gpm and 83 ft TDH. Each pump is v-belt driven at 1320 rpm by an overhead-mounted 25 hp motor. Each pair of pumps discharges to one of two continuously circulating fresh slurry supply headers which run over to the absorber area, past the absorber modules and back to the feed tanks. Header branch connections adjacent to each absorber module feed fresh slurry to the absorber reaction tanks through Clarkson Series C Muscle control valves. One control valve is provided for each absorber module but each valve can be fed from either supply header. The control valve position is regulated by a flow controller. The flow rate set point is determined by an algorithm that responds to inlet $SO_2$ loading in the flue gas entering the absorber modules.

## FORMIC ACID ADDITION SYSTEM

Formic acid is added to the absorbers to improve the efficiency of $SO_2$ removal and sulfite oxidation and to improve limestone utilization. Major components of the formic acid system are the formic acid truck unloading station, the formic acid storage tank and the formic acid metering pumps.

The formic acid truck unloading station is a paved and curbed area just outside the north wall of the FGD building where formic acid deliveries are received and transferred to the formic acid storage tank. A storage tank level indicator is provided for the unloading station operator. The 2-inch unloading line has a manual inlet ball valve at the truck connection and a pneumatic globe valve at the formic acid storage tank.

The storage tank and pumps are enclosed in a separate room inside the FGD building. The room has a diked area to contain spills in the event of a storage tank rupture. The 5,000 gallon capacity, type 316L stainless steel, vertical, cylindrical tank has a design pressure of 15 psig and a design temperature of $100^o$ F. It is equipped with a 6-inch safety relief valve which discharges outdoors.

The formic acid system has three metering pumps, two operating and one common standby. The pumps are Milton Roy Model FR-12100-117 controlled volume (capacity adjustable from 0.6 to 6.2 gallons per hour) simplex diaphragm type with double diaphragm leak detection. They are made of type 316 stainless steel with teflon diaphragms. They are driven by flange-mounted 115 Vac motors. Each pump discharge line is equipped with a pressure relief valve (which discharges back to the pump suction) a pulsation dampener, a pressure gauge and ½-in manual ball valve. The pumps discharge to a common header with manual valving to allow alignment of the standby pump with either absorber module.

## INDUCED DRAFT FANS

Replacement induced draft fans (ID fans) were installed to provide the additional flue gas pressure needed to overcome the resistance of the FGD system. Two 50% capacity fans are provided for each unit. The new ID fans are located in the same location as the old ID fans, between the ESP's and the old chimneys.

The new ID fans are Buffalo Forge HDD (heavy duty) size 2175 centrifugal type D-21, direct-driven by single speed electric motors. The fans are made of carbon steel. Housings are A36. Shafts are A668, Class E. Wheels are A514 Grade B. Hubs are A322 Grade 8620 and A588. Shafts are A668 C1.E. Hubs are shrink-fit to the shafts. Fan bearings have induced air cooling complete with air filters and flexible connections to fan housing and are equipped with RTD's and Bently Nevada seismic transducers. Couplings are Falk Type G-20 LEF.

The Unit 1 fans have a 106.5 inch diameter wheel with backward curved blades. Rated (test block) conditions are 273,819 cfm, 29.4 in WG static pressure and 300 $^{o}$F. The Unit 2 fans are slightly smaller due to the substitution of a non-leak heat pipe type air preheater. The Unit 2 fans have a 103.75 inch diameter wheel with backward curved blades. Rated (test block) conditions are 258,576 cfm, 28.5 in WG static pressure and 280 $^{o}$F. Both the Unit 1 and Unit 2 fans operate at 892 rpm. Fan capacity control is by variable inlet vanes.

Fan motors are 1750 hp, 900 rpm, 4000 Volt, WP-II, 1.15 SF with soleplates, bearing RTD's and Bently Nevada seismic transducers for each bearing.

Each ID fan has a motor-operated, double louver type isolation damper in its outlet duct. The outlet dampers are Effox Double Parallel Louver type, 102-in wide by 102-in tall. Each damper has two sets of parallel louver blades, 5 blades per set. The blades have type 17-4 stainless steel shafts, A36 skins and C276 edge seals. Each set of blades is actuated through an independent double shear crank arm linkage assembly by a Rotork Model 70AR/IW8-60 electric motor actuator. Damper frames are A-36.

The dampers require seal air to prevent flue gas leakage in order to safely isolate a fan while its companion fan is in service. A seal air skid common to both units supplies the seal air requirements for all of the ID fan isolation dampers. The seal air skid includes two Buffalo Forge model 50 AW seal air fans (one operating and one standby) with Ruskin manually operated inlet vane dampers. Fan design capacity is 22,500 cfm at 23-in static pressure. The fans are direct-driven at 1775 rpm by Siemens 60 hp 460 VAC, TEFC motors. Each fan has a Vibra Acoustics I93653-7 inlet filter, a Vibra Acoustics model 23 RHB-31 inlet silencer and a Centerline Series 200 Model 30-AI-65-1-3-5-x butterfly type discharge damper with a Rotork Model 11A/IW5-120 electric actuator. The fans are connected to the seal air distribution duct manifold through a pneumatically operated Y-type diverter gate. A manual knifegate type isolation valve is provided at each damper's seal air connection.

## DUCTWORK AND DAMPERS

A dedicated duct delivers flue gas from each unit's boiler ID fans to the FGD plant. The Unit 1 and Unit 2 inlet ducts are interconnected with a crossover duct. A bypass duct connects the crossover duct to the stack's bypass flue. This arrangement permits flue gas from both boilers to be treated (at reduced load) by a single absorber module. The arrangement also allows either absorber module to be shut down when one of the boilers is off line. The bypass allows the diversion of flue gas around an absorber module during unit startup.

Each absorber module has a motor-operated, guillotine-type inlet damper in its inlet duct and a motor-operated, double louver-type crossover damper in the crossover duct. The crossover duct branches off the inlet duct upstream of the inlet damper. The motor- driven double louver bypass damper, common to both absorber modules, is in the bypass duct between the crossover duct and the stack's bypass flue.

The inlet dampers are Effox Zero Leak Slidegates, 138-in wide by 138-in tall, with 0.75-in thick A-36 blades, C-276 leaf type seals, A-36 frames, chain-driven by Rotork Model 90AR electric actuators with Limitorque H5BC gear boxes.

The crossover dampers are Effox Double Parallel Louvers, 138-in wide by 138-in tall. Each damper has two sets of parallel louver blades, 5 blades per set. The blades have 317LM shafts and skins and C276 edge seals. Each set of blades is actuated through an independent double shear crank arm linkage assembly by a Rotork Model 16A/IW6-70 electric motor actuator. Damper frames are A-36 lined with 317LM.

The bypass damper is an Effox Parallel/Opposed Double Louver, 90-in wide by 90-in tall. It has two sets of louver blades, 4 blades per set. The upstream set has opposed blades, the downstream set has parallel blades. The blades have A-36 skins, 17-4 shafts and C276 edge seals. Each set of blades is actuated through an independent double shear crank arm linkage assembly. The opposed blades are driven by a Rotork Model 11A/IW5-120 electric motor actuator with a 4 to 20 mA positioner. The parallel blades are driven by a Rotork Model 13A/IW4-70 electric motor actuator. Damper frames are A-36.

The dampers require seal air to prevent flue gas leakage in order to allow entry into an absorber which is out of service while either boiler is on line. In addition, the absorber inlet isolation dampers require seal air to prevent flue gas leakage to atmosphere. A common seal air skid supplies the seal air requirements for all five of the dampers in the FGD Plant. The seal air skid includes two Buffalo Forge model 805BL seal air fans (one operating and one standby) with integral, manually-operated inlet vane control. Fan design capacity is 22,500 cfm at 23-in static pressure. The fans are direct-driven at 1780 rpm by Siemens 150 hp 460 VAC, TEFC motors. Each fan has a Vibra Acoustics inlet filter and silencer and a Centerline Series 200 Model 30-AI-65-1-3-5-x butterfly type discharge damper with a Rotork Model 11A/IW5-120 electric actuator. The fans are connected to the seal air distribution duct manifold through a pneumatically operated Y-type diverter gate. A manual knifegate type isolation valve is provided at each damper's seal air connection.

A tuned dissipative silencer is installed in the FGD bypass ductwork to reduce fan noise during bypass operation. The silencer consists of a casing, three internal baffles and a discharge transition. The casing is made of A36 carbon steel. The baffles are made of A569 carbon steel sheet with fiberglass board sound absorptive material in the baffle cavities.

## ABSORBER VESSEL

The absorber vessel is the heart of the FGD plant. It has a foot print of 42ft, 2-in by 79ft, 2-in and an overall height of 108-ft. Its concrete walls are 37-in thick at the base and 20-in thick at the top. A 36-in thick internal partition rises from the floor to the top separating the vessel into two identically sized modules, each with independent flue gas inlet and outlet connections. Each module has a second internal partition which rises from a point 45-ft above the floor to the top, dividing it into cocurrent and countercurrent sections. The inside plan dimensions of the cocurrent section are 11-ft by 35-ft. The countercurrent section is 22-ft by 35-ft. The bottom 20-ft of each module forms the absorber reaction tank. The vessel walls and floor are completely lined with Stebbins ceramic tile. To protect the tile from thermal shock, the top 28-ft of the walls in the cocurrent section are also lined with acid resistant brick.

Flue gas enters the top of the cocurrent section, flows downward through quench sprays and four levels of absorber sprays, crosses under the partition through a set of rubber-lined turning vanes and then upward through three more levels of absorber sprays, through two banks of mist eliminators and out the top of the vessel into the wet stack. The quench sprays and the top two absorber spray banks on the cocurrent side are made of Hastelloy C276. The balance of the absorber spray headers are made of RPS AA150 FRP. The absorber spray nozzles are Lechler helix hollow cone-type made of reaction bonded silicon carbide. As discussed in Section 4.8.5, some of these nozzles were replaced after startup with specially designed suspended impingement cone nozzles made of Stellite® in an attempt to mitigate nozzle plugging and breakage problems. The mist eliminators are Munters chevron-type made of polypropylene. The first (coarse) stage for both modules is Munters model DV-210. The second (finishing) stages for the two modules are different. One module has Munters model DV-2310, the other has Munters model T-271. Wash water sprays are provided to clean upstream and downstream faces of both mist eliminator stages.

## ABSORBER RECYCLE PUMPS

Absorber slurry is pumped to each absorber spray bank from the absorber reaction tank by a dedicated recycle pump. A total of seven pumps are provided for each module, three operating and one spare on the cocurrent side and two operating and one spare on the countercurrent side. The pumps are GIW model FGD 28 rubber-lined horizontal centrifugal-type with corrosion/erosion resistant high chrome white iron impellers and BW/IP RIS-type mechanical seals. The pumps are equipped with Falk Type A horizontal, parallel shaft single reduction speed reducers with water cooled oil bath, Falk Steelflex high speed couplings, Falk double engagement gear type low speed couplings and Reliance 4000 VAC, 1200 rpm, TEFC-XT motors. Pump design capacity is 10,500 gpm. Depending on the spray bank elevation, motor nameplate horsepower range from 350 to 500 and pump speeds range from 574 to 656 rpm. Pump suction and discharge piping is RPS A150 FRP. Each pump has a motor actuated Clarkson Type KGA knife gate isolation valve.

## ABSORBER AGITATORS

Each absorber reaction tank has five agitators to maintain solids in suspension and to mix oxidation air with the absorber slurry to force the bisulfite oxidation reaction. The agitators are Ekato model HWL 100-R. They are side-mounted with mechanical seals and 55-in diameter marine-type impellers constructed of HA 28.5, a corrosion/erosion resistant cast stainless steel similar to Ferralium Alloy 255 with 26 to 28% chrome, 5.5 to 7.5% nickel and 3.5 to 4.5% molybdenum. Agitator shafts are alloy C276. The agitators are driven at 120 rpm by overhead-mounted 25 hp, 1800 rpm motors through a V-belt drive and a Falk size 4307 gear reducer. Oxidation air is injected into the slurry through air lances mounted just in front of four of the five agitators.

## OXIDATION BLOWERS

Oxidation blowers supply air to the oxidation air injection lances in the absorber reaction tanks to force the bisulfite oxidation reaction in order to produce gypsum. Blower design capacity is 4,814 scfm at a discharge pressure of 35 psia. There are 3 blowers, 2 operating and 1 standby. The blowers discharge to a common header which then branches into two headers, one supplying air to each reaction tank. An in-header water spray nozzle quenches the air just before the header branches to the injection lances.

The blowers are Turblex/HV-Turbo Compressor model KA5SV-GL210 single stage, radial type driven by an electric motor through a speed increasing gear. Blower casings are cast iron; impellers are radial flow-type with backward leaning blades machined from aluminum alloy forgings. Capacity control is by adjustable inlet guide vane assemblies mounted integrally with each machine and variable discharge diffusers. Both the guide vanes and the diffusers are electric motor-actuated. The speed increasing gears are single increase, helical parallel shaft-type. The blowers are equipped with inlet filters and silencers, 500 HP motors, lubricating systems, discharge evases and unloading valves and silencers. Each blower, together with its accessories (except for the inlet silencer and blowoff valve) is mounted inside an acoustic enclosure.

## PROCESS WATER

The process water system supplies process water and service water for mist eliminator washing, equipment cooling and hose washdowns. The system consists of a process water tank, three process water pumps (two operating and one standby) and a piping network. Makeup water to the process water tank is provided from the process water reclamation facility (PWRF) which is located southeast of the building. Emergency backup water supply is from power plant house service water via a manual valve. The 29,300 gallon capacity unlined tank is made of carbon steel. The pumps are Goulds Model 3196 LTX ANSI A70 horizontal centrifugal-type with ductile iron casings and impellers, Durametallic mechanical seals, operating at 700 gpm and 275 ft TDH. They are direct-driven at 3560 rpm by 75 hp Reliance TEFC motors.

## CHIMNEY

Each absorber module discharges treated, saturated flue gas to atmosphere through the chimney. The chimney has 3 independent flues, one 12-ft diameter FRP wet flue dedicated to each absorber module and a common 8-ft diameter steel bypass flue. The three flues are supported inside a 40-ft diameter steel chimney that is mounted on the roof of the FGD building.

The FRP flues, fabricated by An-Cor Industrial Plastics using Dow Derakane 510N and 510C-350 resins, have a total length of 227-ft. They extend 50-ft above the top of the chimney. They are supported at a point 50-ft below the top of the chimney so that the top 100-ft of each flue are in compression and the bottom 127-ft are in tension.

The top 50-ft of the bypass flue are made of type 316L stainless steel and the balance is made of A-36 carbon steel. The bypass flue also has a total length of 227-ft and extends 50-ft above the top of the chimney. It is also supported at a point 50-ft below the top of the chimney.

Each flue has continuous emissions monitors (CEMS), lightning rods and aircraft warning lights. The CEMS, furnished by Graseby/STI, has model DP-0701 dilution/extractive type probes and USI Ultraflow 100 ultrasonic flow rate monitors.

An Alimak Alicom 400 service elevator provides access to maintenance and testing platforms inside the chimney.

## GYPSUM DEWATERING

Gypsum solids that form in the absorber reaction tanks are purged from the process by the gypsum dewatering system. The system produces gypsum cake suitable for use in the manufacturing of wallboard and recycles the process liquor. A small fraction of the liquor is processed by the FGD blowdown treatment system to control the accumulation of chlorides.

Each absorber module has two bleed pumps (one operating and one standby) to feed absorber slurry to the primary dewatering hydrocyclones. The pumps are ASH Model 5 x 4 SRH rubber-lined slurry pumps with BW RIS mechanical seals operating at 500 gpm and 139 ft TDH. Each pump is V-belt driven at 1320 rpm by an overhead mounted 40 hp motor. Each module's pumps discharge to one of two headers which carry the slurry over to the hydrocyclones where the header branches to the two primary dewatering hydrocyclone assemblies.

The two primary dewatering hydrocyclone assemblies (one operating and one standby) concentrate the gypsum for further dewatering by centrifuges. The hydrocyclone assemblies provided by Warman each have twelve 6-in size Series C cyclones. The cyclones are made of carbon steel with replaceable rubber liners, ceramic vortex finders and ceramic apexes. The cyclones are arranged in a circle around a central feed manifold. The rubber-lined feed manifold has an internal partition separating it vertically into two halves, each with outlet connections to six cyclones and an independent inlet connected to the bleed header from one of the absorber modules. With this arrangement, six cyclones ( 5 operating and 1 standby) are dedicated to each absorber module. Each cyclone can be isolated from the feed manifold by a Clarkson series KGA manual knifegate valve. Concentrated gypsum discharges through the cyclone apexes to a common underflow launder made of rubber-lined steel. The combined underflow stream is piped to one of the two centrifuge feed tanks. The cyclone overflow streams containing residual fines (2 to 3% solids) discharge to a common overflow launder made of rubber-lined steel. The combined overflow stream is piped to one of the two secondary hydrocyclone feed tanks.

The concentrated gypsum slurry from the primary hydrocyclones is processed by centrifuges to produce a gypsum product meeting specification requirements for purity and surface moisture. The centrifuges are fed through either of two recirculating piping loops, one for each centrifuge tank, by the centrifuge feed pumps. Each loop is capable of processing the waste slurry from both absorber modules. Each loop has one pump. Each loop withdraws slurry from its centrifuge feed tank, routes it past all four centrifuges and returns it to the appropriate tank. Each loop has branch lines adjacent to each centrifuge to deliver slurry to the centrifuge's dual inlet connections. Remotely- actuated valving is provided to allow the operator to align each centrifuge with the desired feed loop.

The centrifuge feed pumps are ASH model 6x6 SRH #4 rubber lined slurry pumps with BW RIS mechanical seals operating at 1000 gpm and 63 ft TDH. The pumps are V-belt driven at 1030 rpm by overhead-mounted 40 hp motors. The 2400 gallon capacity centrifuge tanks are made of carbon steel and lined with rubber. Each tank is equipped with a Lightnin model XLQS-100B, 1.5 hp vertical agitator with rubber-covered shaft and impeller to keep the gypsum solids in suspension. The 24-in. diameter agitator impeller operates at 153 rpm.

The four centrifuges (3 operating and 1 standby) are Krauss Maffei model VZU 160/6.3

vertical basket, batch type machines. Centrifuge housings are of welded construction, lined with rubber. The housing, together with its baseplate, is mounted on elastic-plastic spring elements. The main drive motor (250 hp, 1200 rpm, TEFC) is installed on a laterally protruding section of the base plate. The basket has a central hub which is supported on a cartridge-type bearing assembly mounted in the hub of the housing. The bearing assembly includes the centrifuge's vertical shaft which is made of high quality heat-treated steel and which is provided with a conical seat on top for installing the basket. The shaft is V-belt driven through a pulley fitted to its lower end. A variable frequency drive (Robicon ID-CSI 456 series) is provided to automatically control the motor and basket speeds. The basket is of rubber-lined welded construction. It has an inside diameter of 1600mm, a nominal height of 1250mm and 6.3 $m^2$ of filtering area. It has a polypropylene support mesh and DIN 1.4401 stainless steel filter cloth.

Gypsum slurry enters the centrifuge through two Hastelloy C4 feed pipes. A manually set control valve in the piping to each fill connection regulates the centrifuge fill rate. The feed pipes inject the slurry onto the inside surface of the basket tangentially, providing a uniform distribution over the entire basket. Feed pipe position is adjustable vertically and radially for optimum distribution. A limit switch-type feed controller prevents the basket from being over-filled. Primary control of the feed is by a timer. Feed slurry density and flow rate measurements in the feed loop are used in a control algorithm to calculate the required feed duration. The centrifuge has a Hastelloy C4 wash pipe to wash soluble contaminants, primarily chlorides and fluorides, from the gypsum filter cake. The wash pipe, which is bolted to the upper housing section, has type 316 stainless steel nozzles to allow a uniform distribution of wash water over the total basket height. The spray nozzles are directed perpendicular to the inside basket wall. The centrifuge has a Hastelloy C4 heel cake wash pipe to flush residual cake from the basket after the gypsum has been discharged. The wash pipe which is bolted to the upper housing section has flat jet nozzles made of type 316 stainless steel to uniformly wash the basket over its entire height. Another spray nozzle flushes the basket hub. The centrifuge has a scraper to remove product gypsum cake from the basket.

Centrifuge filtrate passes through the basket and exits the casing through a tangential discharge connection and is piped to the filtrate tanks**.** Remotely actuated valving is provided to allow the operator to align each centrifuge with the desired filtrate tank. After the gypsum has been washed and spun dry, the basket speed is reduced and the scraper, a hard faced, single motion broad knife, is gradually rotated into the cake by a hydraulic cylinder. As the cake is peeled from the inside surface of the basket it falls through the Hastelloy C22 discharge chute, through the diverter chute, and onto the discharge conveyor. The diverter chute is automatically shifted between two positions by a Schrader NC9/A2 pneumatic cylinder. During the feed, wash, spin and flush steps the diverter chute is positioned to collect filtrate from the discharge chute and divert it through a flexible hose to the filtrate tank. Remotely-actuated valving is provided to allow the operator to align each centrifuge with the desired filtrate tank. During the cake discharge step the diverter chute is positioned to collect and direct the cake onto the discharge conveyor.

## CLARIFIED WATER SYSTEM

As noted above, the overflow streams from the primary dewatering hydrocyclone assemblies are collected in the secondary hydrocyclone feed tanks. Two feed tanks are provided, one connected to each primary dewatering hydrocyclone assembly. The 4400 gallon capacity tanks are made of carbon steel and lined with Dudick Protecto-Flake 800 glassflake-filled, trowel-applied low-permeability, high molecular weight vinyl ester lining. Each tank is equipped with a Lightnin model 71QS1, 1 hp vertical agitator with rubber-covered shaft and impeller to keep the gypsum solids in suspension. The 36 in. diameter agitator impeller operates at 84 rpm.

A portion of the slurry collected in the secondary hydrocyclone feed tanks is processed by the secondary hydrocyclones to remove most of the residual gypsum from the primary hydrocyclone overflow to produce clarified water for use in limestone slurry preparation, FGD system flushing and for processing by the FGD blowdown treatment system to control the accumulation of chlorides. The balance of the slurry collected in the secondary hydrocyclone feed tanks is allowed to overflow to the filtrate tanks to be recycled to the absorbers.

Each secondary hydrocyclone feed tank has one secondary hydrocyclone feed pump to feed slurry to one of the secondary hydrocyclone assemblies. The pumps are ASH model 4 x 3 SRH rubber-lined slurry pumps with BW RIS mechanical seals operating at 271 gpm and 91 ft TDH. Each pump is V-belt driven at 1860 rpm by an overhead-mounted 15 hp motor.

The hydrocyclone assemblies provided by Warman each have six 4-in size Series C cyclones (5 operating and 1 standby). The cyclones are made of carbon steel with replaceable rubber liners, ceramic vortex finders and ceramic apexes. The cyclones are arranged in a circle around a central feed manifold. The rubber lined feed manifold has outlet connections to the six cyclones and an inlet connected to the feed header from one of the secondary hydrocyclone feed pumps. Each cyclone can be isolated from the feed manifold by a DIA-FLO manual diaphragm valve. Residual gypsum (10% solids) discharges through the cyclone apexes to a common underflow launder made of rubber-lined steel. The combined underflow stream is piped to one of the two filtrate tanks. The cyclone overflow streams (0.5% solids) discharge to a common overflow launder made of rubber lined steel. The combined overflow stream is piped to one of the two clarified water tanks.

Two clarified water tanks are provided, one connected to each secondary hydrocyclone assembly. The 63,450 gallon capacity tanks are made of carbon steel and lined with Dudick Protecto-Flake 800 glassflake-filled, trowel-applied low-permeability, high molecular weight vinyl ester lining. Each tank is equipped with a Lightnin model 75QS3, 3 hp vertical agitator with rubber-covered shaft and impeller to keep the gypsum solids in suspension. The 72-in diameter agitator impeller operates at 37 rpm. The clarified water pumps, one dedicated to each tank, deliver clarified water from the tanks for use in limestone slurry preparation, for process pipeline flushing, and to blow down process liquor to the FGD Wastewater Treatment System.

## FILTRATE RETURN SYSTEM

The filtrate return system recycles filtrate from the gypsum dewatering system to the absorber reaction tanks. The system includes the filtrate tanks, filtrate pumps and associated piping, valves and controls. The primary inputs to the filtrate tanks are filtrate from the centrifuges, excess primary hydrocyclone overflow from the secondary hydrocyclone feed tanks and underflow from the secondary hydrocyclones. Overflow streams from the clarified water tanks and from the centrifuge feed tanks are also collected in the filtrate tanks. Two filtrate tanks are provided, one connected to each secondary hydrocyclone assembly, secondary hydrocyclone feed tank, centrifuge feed tank and clarified water tank.

The 20,750 gallon capacity tanks are made of carbon steel and lined with Dudick Protecto-Flake 800 glassflake-filled, trowel-applied low-permeability, high molecular weight vinyl ester lining on the tank walls and cover and with Dudick Protecto-Line 800 glassflake-filled, reinforced vinyl ester lining on the tank floor and for 1-ft. up the tank wall. Each tank is equipped with a Lightnin model 73QS1.5, 1.5 hp vertical agitator with rubber-covered shaft and impeller to keep the gypsum solids in suspension. The 63-in. diameter agitator impeller operates at 36 rpm.

The filtrate pumps, one dedicated to each tank, are ASH model 6 x 6 SRH rubber-lined slurry pumps with BW RIS mechanical seals operating at 1000 gpm and 49 ft TDH. The pumps are V-belt driven at 915 rpm by overhead-mounted 40 hp motors. Robicon model ID-454 variable frequency drives provide pump speed adjustment to control tank level in the filtrate tanks. The pump discharge lines are interconnected to allow either pump to serve both reaction tanks. Each pump can also be dedicated to one reaction tank.

## GYPSUM HANDLING

The gypsum handling system transfers gypsum cake containing 6% to 8% surface moisture from the centrifuges to the gypsum storage building located about 50 feet north of the FGD building. Gypsum discharged from each centrifuge falls through a chute onto one of two 24-in wide, 28-ft long, 100 tons per hour capacity belt conveyors, the gypsum collecting conveyors, located on the floor below the centrifuges. Each collecting conveyor handles the discharge from two of the four centrifuges. Each collecting conveyor discharges through a chute onto one of the two gypsum transporting conveyors, 24" wide, 100 tons per hour capacity belt conveyors, which travel through a tubular conveyor gallery to the storage building. The transporting conveyors discharge onto a 24-in wide, 40-ft long, 100 tons per hour capacity reversing shuttle conveyor in the storage building. The shuttle conveyor builds a storage pile of approximately 4400 tons on the floor of the storage building. The conveyors have screw take-ups. They are electric motor driven through Nuttal gear reducers. They have alignment switches, speed switches, safety pull cords, warning horns and plugged chute switches and air cannons at each transfer point. The shuttle conveyor has position switches to set its discharge points as well as end and over-travel position switches. The storage building is a modified A-frame steel-sided structure with concrete retaining walls. It has a footprint of 75-ft by 104-ft and an overall height of about 60-ft. A front end loader works in the storage building loading gypsum onto transport trucks for export to the end user.

The gypsum handling system was designed and supplied by FMC's Material Handling Systems Division.

## SUMPS AND DRAINS

The FGD plant has a system of sumps and drains to collect and recycle various process and waste liquid streams. There are seven sumps in the FGD plant, the Unit 1 and Unit 2 absorber area sumps, the waste water treatment area sump, the north and south equipment drain sumps, the limestone prep area sump and the absorber slurry drain tank area sump. All of the sumps, except for the equipment drain sumps and the absorber slurry drain tank area sump, are designed to handle process slurries. They each have an agitator and dual vertical sump pumps. They are lined with Dudick Protecto-Line 800 trowel-applied, reinforced vinyl ester. The absorber area sump agitators are Lightnin model 73Q5, 5 hp vertical agitator with rubber-covered shaft and impeller. They have 55-in diameter impellers which operate at 68 rpm. The limestone prep area sump agitator and the waste water treatment area sump agitator are Lightnin model 72Q2, 2 hp vertical agitators with rubber-covered shafts and impellers. They have 33-in diameter impellers which operate at 100 rpm. Absorber area sump pumps are Warman 65 QVSPR rubber-lined vertical centrifugal-type, V-belt driven by 25 hp motors at 1570 rpm to deliver 300 gpm at 90-ft TDH. The pump discharges can be directed to either of the absorber reaction tanks or to the absorber drain tank. Limestone prep area sump pumps and waste water treatment area sump pumps are Warman 40 PVSPR rubber-lined vertical centrifugal type, V-belt driven by 7.5 hp motors at 1988 rpm to deliver 100 gpm at 65-ft TDH. The limestone prep area sump pumps can be directed to either of the absorber reaction tanks. The waste water treatment area sump pumps can be directed to either of the absorber reaction tanks or to the blowdown equalization tank.

The north and south equipment drain sumps are unlined. They have dual vertical centrifugal type 100 gpm capacity sump pumps. The pumps discharge to the main plant's wastewater treatment system. The absorber slurry drain tank area sump is lined with Dudick Protecto-Line 800 trowel-applied, reinforced vinyl ester. It has a single vertical centrifugal-type 100 gpm capacity sump pump. The pump discharges to the absorber slurry drain tank.

## ABSORBER DRAIN TANK

The absorber slurry drain tank provides a place to store absorber slurry when an absorber reaction tank must be drained for maintenance. Slurry can be transferred to the tank by the gypsum bleed pumps and by the absorber area sump pumps. The 290,000 gallon capacity tank is made of reinforced concrete lined with coal tar epoxy. It is equipped with a Lightnin model 780Q15, 15 hp vertical agitator with rubber-covered shaft and impeller to keep the gypsum solids in suspension. The 146-in diameter agitator impeller operates at 20 rpm. The absorber slurry drain pumps, one operating and one standby, return slurry to the absorber reaction tanks. The pumps are ASH model 5 x 4 SRH rubber-lined slurry pumps with BW RIS mechanical seals operating at 500 gpm and 76-ft TDH. The pumps are V-belt driven at 1265 rpm by overhead-mounted 20 hp motors.

## FGD BLOWDOWN TREATMENT

Chlorides introduced into the system by the coal are scrubbed from the flue gas by the FGD system. Because commercial grade gypsum specifications limit the allowable chloride content, the concentration of chlorides in the scrubbing liquor will increase without limit unless some of the liquor is blown down. The FGD blowdown treatment system processes a blowdown stream of clarified (secondary hydrocyclone overflow) water to control the accumulation of chlorides to acceptable levels. The design concentration of chlorides is 40,000 ppm. The blowdown pre-treatment system removes suspended solids and dissolved species, particularly heavy metals and magnesium, from the blowdown prior to discharge or processing in the brine concentrator. Removal of these constituents is necessary to meet discharge permit requirements and to maintain salable quality calcium chloride as a brine concentrator product.

The blowdown pre-treatment system consists of the following major components: equalization tank, reaction tanks, the DensaDeg® unit, the sludge handling system, the lime slurry feed system and the chemical feed system.

The 16,000 gallon capacity equalization tank provides the surge capacity required to stabilize the flow rate through the treatment system. The tank is made of carbon steel lined with natural rubber. It is equipped with a Lightnin model 73QS3, 3 hp vertical agitator with rubber-covered shaft and impeller to keep the solids in suspension. The 47-in diameter agitator impeller operates at 68 rpm. The forward feed pumps, one operating and one standby, transfer slurry from the equalization tank to the reaction tanks. The pumps are Warman model 1.5/1 BAH rubber-lined horizontal centrifugal slurry pumps with BW RIS mechanical seals operating at 30 gpm and 30-ft TDH. The pumps are V-belt driven by overhead-mounted 2 hp motors.

Three reaction tanks are connected in series. Slurry from the forward feed pumps flows by gravity through each tank in turn and then into the Densadeg® unit. The first tank in the series is the pH elevation/desaturation tank. This 3225 gallon capacity tank is made of carbon steel lined with natural rubber. It is equipped with a Lightnin model 14QS2, 2 hp vertical agitator with rubber-covered shaft and impeller to keep slurry solids in suspension. The 30-in diameter agitator impeller operates at 82 rpm. Lime slurry is added to obtain a pH of 11.0 to 11.2, fully neutralizing the mineral acids present in the blowdown stream and initiating metal hydroxide precipitation. Gypsum sludge drawn from the downstream Densadeg® unit is also added to accelerate gypsum precipitation in order to prevent scaling downstream.

The second tank in the series is the heavy metal precipitation tank where an organosulfide can be added, if needed, to achieve further heavy metal precipitation. This 800 gallon capacity tank is made of carbon steel lined with natural rubber. It is equipped with a Lightnin model XJC-43, 1.5 hp vertical agitator with rubber-covered shaft and impeller to keep slurry solids in suspension. The 12-in diameter agitator impeller operates at 350 rpm.

The third tank in the series is the coagulation tank where a mineral coagulant, ferric chloride, is added to the blowdown stream. This 420 gallon capacity tank is made of carbon steel lined with natural rubber. It is equipped with a Lightnin model XJC-43AM, 1.5 hp vertical agitator with rubber-covered shaft and impeller to keep slurry solids in suspension. The 12-in diameter agitator impeller operates at speeds varying from 70 to 350 rpm.

From the coagulation tank the blowdown stream flows by gravity to the Densadeg® unit. The Densadeg® has three-stages: a solids contact reaction zone (Densadeg® Reactor), a presettler-thickener zone and a lamellar settling tube clarifier zone. The reaction zone consists of a 700 gallon capacity rubber-lined carbon steel tank with a high energy axial flow mixer. The mixer is a Eurodrive model RF60VZ11DT, 2 hp variable speed (35 to 170 rpm) axial flow mixer with rubber-covered shaft and impeller. Anionic polymer flocculant is added and wastewater is recirculated by the mixer, densifying the precipitated metal hydroxide particles. The wastewater is forced upward by the mixer, over a weir and through a spillway to the presettler-thickener zone.

The Densadeg® presettler-thickener zone and clarifier zone are housed in a 14-ft, 6-in diameter, 39-ft tall cone-bottomed tank made of carbon steel lined with natural rubber. As the blowdown stream enters the presettler-thickener zone it is forced downward by means of a baffle, giving the floc particles downward momentum which assists their settling. The resulting sludge is allowed to thicken and is forced to the center well by a rotary scraper mechanism. The scraper shaft and arms are made of rubber-lined steel. The scraper is driven by a DBS model SE-25-3 1 hp variable speed drive at 0.2 to 0.04 rpm. Sludge is withdrawn from the tank at two locations. Sludge withdrawn from the sidewall about 1 ft. above the bottom is recycled by sludge recycle pumps to the pH elevation/desaturation tank to accelerate gypsum precipitation in order to prevent scaling. The sludge recycle pumps (1 operating and 1 standby) are Seepex model 5-6LBN/1.3.8-6774-303-1.3/2.1 variable speed, rubber-lined progressive cavity-type operating at 5 to 20 gpm and 30 psig. Sludge withdrawn from the center well is transferred by sludge waste pumps to the sludge holding tank prior to dewatering by the filter press. The sludge waste pumps (1 operating and 1 standby) are Seepex model 17-6LBN/1.3.8-6774-303-1.3/2.1 variable speed, rubber-lined progressive cavity-type operating at 15 to 50 gpm and 30 psig. After dropping out its precipitated solids the blowdown stream flows upward through a bank of inclined lamellar settling tubes in order to capture fugitive solids before exiting the Densadeg® through a V-notch type overflow weir and flowing by gravity to the brine concentrator storage tank. Water exiting the lamellar settling tubes generally has a suspended solids content of less than 20 mg/l. The clarified blowdown is monitored for pH and turbidity and automatically diverted to the equalization tank if it doesn't satisfy brine concentrator inlet requirements.

Thickened sludge from the Densadeg® unit is stored in the sludge holding tank prior to dewatering by the filter press. Lime slurry is added to the holding tank to improve sludge dewatering characteristics. Waste sludge from the brine concentrator underflow pump is also stored in the tank. The 24,200 gallon capacity 16-ft diameter, 31-ft tall cone-bottomed holding tank is made of carbon steel lined with natural rubber. It is equipped with a Lightnin model 74QS10, 10 hp vertical agitator with rubber-covered shaft and impellers to keep the sludge solids in suspension. The two 57-in diameter agitator impellers operate at 68 rpm.

A Perrin Model 200-S-48-60/70 R1.26 plate and frame filter press is used to dewater both the FGD blowdown treatment sludge and the sludge from the main plant's coal pile runoff treatment system. Coal pile runoff (CPR) sludge is stored in the CPR/MCW sludge holding tank in the FGD building prior to being processed by the filter press. The 10-ft diameter, 8-ft tall flat-bottomed holding tank is made of FRP. The press processes sludge from only one of the tanks at a time. A common filter press feed pump is connected to both of the sludge holding tanks. Remotely actuated valving allows the control room operator to align the pump with either of the two tanks. The filter press feed pump is a Josef Emmerich piston diaphragm model SP529GASH operating at 90 gpm and 225 psi. The pump is driven by a 20 hp motor. Filter cake from the press is discharged through moveable FRP drip trays into a dumpster on the floor below. When processing the FGD sludge, filtrate from the press is recycled by gravity to the equalization tank. When processing CPR sludge, filtrate from the press is collected in the 3500 gallon capacity CPR/MCW filtrate tank and returned to the main plant's MCW basin by the CPR/MCW filtrate pump. The CPR/MCW filtrate pump is an ASH model 4 x 3 SRH rubber-lined slurry pump with BW RIS mechanical seal operating at 250 gpm and 30 ft TDH. The pump is V-belt driven by an overhead-mounted 7.5 hp motor. The CPR/MCW filtrate tank is made of FRP.

Lime slurry from the main plant's wastewater treatment system is stored in the lime slurry tank in the FGD plant for use by the FGD blowdown treatment system. The 575 gallon capacity tank is made of carbon steel and rubber-lined. It is equipped with a Lightnin model XJC-87, 1 hp vertical agitator with rubber-covered shaft and two rubber-covered 12-in diameter impellers to keep the lime solids in suspension. The two lime slurry pumps (one operating and one standby) which deliver lime slurry to the process are Warman model 1.5/1 BAH rubber-lined slurry pumps with BW RIS mechanical seals operating at 70 gpm and 50 ft TDH. The pumps are V-belt driven by overhead-mounted 3 hp motors.

Ferric chloride is fed to the coagulation tank from the 200 gallon capacity ferric chloride Storage tank by two ferric chloride feed pumps, one operating and one standby. The pumps are Prominent model G/4-I 1202 PP with maximum capacity of 1.6 liters/hr at 30 psi. The tank is made of FRP.

Organosulfide solution is fed to the heavy metal precipitation tank from the 132 gallon capacity organosulfide storage tank by two organosulfide feed pumps, one operating and one standby. The pumps are Prominent model G/4-I 1202 PP with maximum capacity of 1.6 liters/hr at 30 psi. The tank is made of FRP.

## BRINE CONCENTRATOR SYSTEM

The FGD brine concentrator system was designed to remove chlorides from the FGD blowdown pre-treatment system effluent, producing a concentrated calcium chloride brine stream that can be commercially marketed and a distillate (pure water) stream for recycle to the FGD process as makeup water. The brine concentrator system has several subsystems including chemical addition, brine concentrator feed, brine concentrator, distillate and brine concentrator waste.

The purpose of the chemical addition subsystem is to condition the treated effluent from the FGD blowdown pre-treatment system to prevent scaling of heat transfer by adding hydrochloric acid and scale inhibitor to the brine concentrator feed tank. Hydrochloric acid acts to prevent carbonate scaling by maintaining a feedwater pH of 5.5, breaking down the carbonates and releasing $CO_2$ which is removed in the deaerator downstream. The acid is continuously fed from the 55 gallon capacity acid feed tank to the brine concentrator feed tank by the acid metering pumps. The tank is made of PVDF. The two metering pumps (one operating and one standby) are Prominent GAMMA 4I 1201 TT hydraulically actuated diaphragm-type with teflon wetted parts and a nominal capacity of .084 gph.

The purpose of the scale inhibitor is to prevent scaling of the secondary heat exchanger. A concentration of 10 to 15 ppm of inhibitor is needed to prevent precipitation of calcium sulfate as the feedwater is heated to $180^0$ F. Scale inhibitor is continuously added to the brine concentrator feed tank by two scale inhibitor metering pumps (one operating and one standby) from the 55 gallon capacity scale inhibitor feed tank. The tank is made of polyethylene. The pumps are Prominent GAMMA 4I 1201 TT hydraulically actuated diaphragm-type with polypropylene wetted parts and a nominal capacity of .036 gph.

The purpose of the brine concentrator feed subsystem is to supply pre-heated and deaerated feedwater to the brine concentrator. Major subsystem components include the brine concentrator storage tank, the FGD blowdown transfer pumps, the brine concentrator feed tank, the brine concentrator primary and secondary fed pumps, the primary and secondary heat exchangers, the deaerator, the barometric condenser and the condenser ejector.

Treated effluent from the Densadeg® unit of the FGD blowdown pre-treatment system flows by gravity into the brine concentrator storage tank. This 19,000 gallon capacity tank provides the surge capacity necessary to guarantee a steady flow rate through the brine concentrator. It is made of carbon steel lined with Dudick Protecto-Flake 800 glassflake-filled, trowel-applied low-permeability, high molecular weight vinyl ester lining. It is equipped with a Lightnin model 74QS2, 2 hp vertical agitator with rubber-covered shaft and impellers to keep the sludge solids in suspension. The two 42-in diameter agitator impellers operate at 68 rpm. The water is transferred from the storage tank to the brine concentrator feed tank by the FGD blowdown transfer pumps, one operating and one standby. The pumps are Goulds model 3196, 1 x 1.5-8 STX horizontal centrifugal-type with type 316 stainless steel casing, impeller and shaft, monel shaft sleeve and mechanical seals operating at 30 gpm and 50 ft TDH. The pumps are direct driven at 1800 rpm by 3 hp motors**.**

The 300 gallon capacity brine concentrator feed tank provides the residence time needed for complete mixing of the hydrochloric acid and scale inhibitor with the feedwater. The FRP tank is equipped with a Lightnin model V5Q25**,** 1/3 hp vertical agitator with rubber-covered type 316L stainless steel shaft and impellers to ensure complete mixing. The two 10-in diameter agitator impellers operate at 342 rpm.

The brine concentrator primary feed pumps (one operating and one standby) are provided to pump the feedwater from the feed tank through the primary heat exchanger and into the deaerator. The pumps are Goulds model 3196, 1 x 1.5-8 STX horizontal centrifugal-type with monel impellers, type 316 stainless steel shafts, monel shaft sleeves and mechanical seals operating at 40 gpm and 140-ft TDH. The pumps are direct driven by 7.5 hp motors.

The function of the primary heat exchanger is to preheat the feed water to $150^0$ F by exchange with brine concentrator distillate. The counter-flow heat exchanger is an APV Crepaco model SR25 plate and frame-type, constructed of grade 1 titanium. It has a total heat load of 1,315,800 Btu/hr. Plates are 0.6 mm thick. Design temperature is $250^0$ F. Design pressure is 150 psig.

The function of the deaerator is to remove non-condensable gases from the feedwater after it is preheated by the primary heat exchanger. If not removed the dissolved oxygen in the feedwater would tend to cause corrosion in the system. Also, the gases would release in the boiling atmosphere of the brine concentrator sump and would interfere with heat transfer in the condenser section of the brine concentrator. The deaerator, a 16-in diameter, 16.5-ft tall column made of FRP with 15 cu.ft. of Koch 1-in polypropylene Flexisaddle Super Intalox packing, has a design capacity of 31 gpm and a design temperature of $200^0$ F.  The deaerator operates under partial vacuum.  The feedwater is sprayed through the deaerator nozzle onto the surface of the packing material.  Some of the feedwater flashes into vapor, releasing non-condensable gases which are withdrawn and vented to atmosphere through the barometric condenser/condenser ejector.  The barometric condenser/condenser ejector is a Croll-Reynolds model B6-101 Air Operated Evactor with FRP and 316 stainless steel wetted parts.  It is a direct contact type heat exchanger which condenses deaerator vapor by mixing with feedwater from the brine concentrator primary feed pumps.  It has a design temperature of $160^0$ F.  The vapor condensed by the barometric condenser is returned by gravity to the brine concentrator feed tank.  The balance of the feedwater (the portion that does not flash) collects in the bottom of the deaerator.

The brine concentrator secondary feed pumps (one operating and one standby) are provided to pump feedwater from the deaerator through the secondary heat exchanger and into the sump section of the brine concentrator.  The pumps are Goulds model 3196, 1 x 1.5-8 STX horizontal centrifugal-type with CD4MCU casings and impellers, type 316 stainless steel shafts, CD4MCU shaft sleeves and mechanical seals operating at 30 gpm and 140 ft TDH.  The pumps are direct driven at 3600 rpm by 7.5 hp motors**.**

The function of the secondary heat exchanger is to heat the deaerated feedwater to $209^0$ F by exchange with brine concentrator distillate.  The heat exchanger is APV Crepaco model SR25 plate and frame-type, constructed of grade 1 titanium.  It has a total heat load of 903,300 Btu/Hr.  Plates are 0.6 mm thick.  Design temperature is $250^o$ F.  Design pressure is 150 psig.

The brine concentrator subsystem is a vapor compression type falling film evaporator for separating the feedwater into two streams, a clean distillate stream for return to the FGD system and a concentrated brine stream for export as a byproduct.  Major subsystem components include the brine concentrator, the recirculation pump and the brine concentrator vapor compressor.

The brine concentrator assembly consists of vertical shell and tube heat exchanger (the condenser) with a floodbox over the upper tube sheet, mounted on top of a sump.  The entire assembly is supported by a skirt and has an overall height of 47-ft.  The condenser tube bundle has 370 titanium (SB-338-7W) tubes , each 2-in diameter and 25-ft long.  The tube bundle is housed in a 54-in diameter type 316L stainless steel shell and is terminated at each end by a 1-in thick titanium (SB-348-7) tube sheet.  The upper tube sheet serves as the floor of the titanium (SB-265-7) floodbox which forms the top of the condenser.  The floodbox is 54-in diameter and 37-in tall, capped by a titanium (SB-265-7) dished head.  The lower tube sheet is located in the steam cavity at the top of the sump.  The sump is 90-in diameter by 17.5-ft tall with a cone bottom and a cone top.  It is made of titanium (SB-265-7) and has a working volume of 4000 gallons.  The condenser shell side and tube side are designed for full vacuum and 25 psig at $450^o$ F.

The floodbox forms a space above the upper tube sheet where the brine slurry is delivered to the condenser by the recirculation pump. The brine is sprayed downward into a 24-in diameter cylindrical inlet strainer assembly which is mounted above the upper tube sheet. The titanium (SB-265-7) strainer has perforated walls and a perforated cone bottom which slopes to 1.5-in diameter drain which is piped through one of the condenser tubes to the sump. Large particles that could plug the flow distributors are trapped by the strainer and returned to the sump where continued passes through the recirculation pump eventually pulverizes them. Brine passing through the strainer is distributed down the inside of the condenser tubes. The flow per tube and the recirculation pumping rate are designed to maintain a flooded level above the tube sheet (approximately 11-in). A distributor at the top of each tube regulates the volume of brine flowing down the tube and distributes the brine to the tube wall in a thin uniform film. To assist equal distribution three of the tubes are used to equalize the pressure between the floodbox and the sump steam cavity.

Steam supplied to the shell side of the condenser by the vapor compressor provides the heat necessary to concentrate the brine by evaporation. The concentrated brine flowing down the condenser tube walls together with steam evaporated from the brine pass through the lower tube sheet into the sump. The sump collects the falling brine and serves as a head tank for the recirculation pump which returns the brine to the floodbox at a circulation rate of 1820 gpm. The brine slurry contains approximately 3.6% suspended solids. The circulation rate turns over the entire volume of the sump once every two minutes which, together with the sump's sloped bottom, prevent the solids from settling. The recirculation pump is Goulds model 3196, 8 x 10-15G XLTX with cast Ferralium 255 casing, impeller and shaft sleeve, type 4140 steel shaft and a mechanical seal operating at 1820 gpm and 90-ft TDH. The pump is direct driven at 3600 rpm by a 30 hp motor.

The area between the sump liquid level and the top of the sump wall is the steam cavity. The top of the sump wall is angled inward to form an inverted conic section, which supports the condenser. The condenser extends downward just past the bottom of the cone, where the lower tube sheet is suspended approximately 3-ft above the sump liquid level. The steam evaporated from the brine is drawn upward to the vapor compressor suction through mist eliminator pads in the annular space between the sump wall and the condenser shell. The mist eliminators remove entrained suspended solids from the vapor. Automatic sprays use hot distillate to remove deposits from the mist eliminator pads. The vapor compressor heats the steam by vapor compression and discharges it into the condenser shell. Steam is condensed on the outside of the condenser tubes as it gives up heat to the brine. This condensate flows down the outside of the condenser tubes to the bottom of the condenser. Condensate collected at the bottom of the condenser passes through a perforated collection pipe to the distillate tank.

The vapor compressor is an Ingersoll-Rand model M93-7030 25STM1, X-FLO single stage Turbo-type of integral gear design. When fully loaded the compressor increases the steam pressure/temperature from 6.5-in$H_2O$/240$^0$ F to approximately 27 PSIA/400$^0$ F. Two bypass lines are provided from the vapor compressor discharge back to its suction. One bypass is opened during compressor startup to prevent surging. The second bypass is used to superheat the suction steam to prevent water erosion of the compressor impeller. Sealing steam is supplied to the compressor from the auxiliary steam system. A Reliance 450HP/4000V/3600rpm WP-II motor drive is direct-coupled to the compressor's bull gear shaft. The bullgear drives a high speed pinion shaft upon which the compressor's impeller is mounted. The normal impeller speed is 34,292 rpm. The gear casing is horizontally split allowing easy access to the gearing, bearings and seals. Compressor capacity control is by a pneumatically actuated inlet guide vane assembly mounted on the intake housing and bolted to the diffuser volute. The compressor was backfitted after start-up with a check valve to prevent reverse rotation and a backpressure control valve to mitigate excessive vibration. The compressor has a completely self-contained lubrication system mounted on the baseplate. The lubrication system consists of an oil reservoir located in the baseplate, main and auxiliary oil pumps, oil cooler and filter together with piping and accessories. The main oil pump is directly mounted on the bullgear. Oil is drawn from the oil reservoir and passes through the oil cooler and oil filter. The auxiliary oil pump is separately driven by an electric motor. It serves to prime the main oil pump and flood the compressor bearings and oil lines before the compressor starts. The entire compressor assembly is housed in a custom-designed sound enclosure.

The distillate subsystem consists of the distillate tank and the two distillate pumps (one operating and one standby). Distillate (condensate) produced by the brine concentrator is collected in the distillate tank. During normal operations the distillate tank is continuously vented to atmosphere. Venting is necessary to remove non-condensable gases that were swept to the tank from the condenser. Venting is also used to remove excess energy from the brine concentrator. The 240 gallon capacity distillate tank is a 36-in diameter by 7-ft tall ASME coded pressure vessel made of type 316L stainless steel with a design temperature of 200$^0$ F and a design pressure of 25 psig internal and 2 psig external.

Distillate is transferred from the distillate tank, through the secondary and primary heat exchangers to the FGD process water storage tank by one of the two distillate pumps. Mechanical seal flush water is provided by cooled distillate. The distillate pumps are Goulds model 3196, 1 x 1.5-8 STX horizontal centrifugal-type with type 316 stainless steel casings, impellers and shaft sleeves, type 4140 steel shafts and mechanical seals operating at 30 gpm and 250-ft TDH. The pumps are direct-driven at 3600 rpm, 15 hp motors**.**

The function of the brine concentrator waste subsystem is to control the concentration of dissolved and suspended solids in the brine concentrator sump by processing bleed streams from the discharge of the recirculation pump. The major components of the subsystem include the seed recycle pump, the seed hydrocyclone, the product tank and the underflow pump.

As water is evaporated from the recirculating brine solution the concentration of the remaining brine increases and salt compounds start to precipitate. The first salt compound to precipitate is calcium sulfate. The brine concentrator is designed to precipitate calcium sulfate only. If the brine concentration becomes too high secondary salts begin to precipitate. Because of their physical characteristics precipitation of these secondary salts is undesirable. Control of the concentration of the brine in the sump is therefore essential. The density of the brine solution is dependent on the Total Solids in solution. The Total Solids are the sum of the concentrations of precipitated solids (Total Suspended Solids or TSS) and Total Dissolved Solids (TDS). The concentration of suspended solids in the brine is also critical. There must be enough TSS to completely surround each developing salt crystal with a similar surface for it to adhere to. Otherwise it would adhere to a tube wall, scaling and eventually plugging the tube.

The waste subsystem must therefore maintain a high enough TSS to prevent scaling and, at the same time, maintain a low enough TDS to prevent precipitation of secondary salts. This is accomplished by using two blowdown streams, one for TDS control and one for TSS control. Both streams are drawn from the recirculation pump discharge header. One of the streams, the TDS control stream, is pumped through the seed hydrocyclone by the seed recycle pump. The seed recycle pump is a Goulds model 3196, 1 x 1.5-8 STX horizontal centrifugal-type with type 4140 steel shaft, Hastelloy C shaft sleeve with a mechanical seal operating at 20 gpm. The pump is direct-driven by a 3 hp motor. The seed hydrocyclone is a Krebs model HCY-311 with Kynar apex valve, alumina cyclone head with integral vortex finder and alumina cylindro-conical section. Suspended solids (seed crystals) are centrifugally separated from the brine as it passes through the seed hydrocyclone. The tangential inlet to the hydrocyclone creates a rotational flow around the axis of the hydrocyclone. Centrifugal force drives the suspended solids towards the wall of the hydrocyclone. These suspended solids flow by gravity down through the apex. This underflow fraction, containing approximately 90% of the suspended solids in the hydrocyclone feed, is returned to the recirculation pump suction line. The clarified brine flows inward, along the axial center of the hydrocyclone to the hydrocyclone's overflow outlet. This overflow fraction, free of suspended solids, is split into two branches. One branch is returned to the discharge of the recirculation pump. The other branch discharges through a control valve to the product tank. The control valve is positioned to maintain constant TDS as reflected by the density measured in the hydrocyclone overflow stream (which is free of suspended solids).

The second blowdown stream, the TSS control stream, flows through a control valve directly to the product tank. The control valve is positioned to maintain constant TSS as reflected by the difference between two density measurements, the density of the brine in the recirculation pump discharge line (reflective of Total Solids) and the density of the brine in the hydrocyclone overflow stream (reflective of TDS).

The product tank holds both the TSS and TDS blowdown streams. The 4860 gallon capacity, 7-ft diameter, 20-ft tall cone-bottom tank is made of FRP. It is designed for atmospheric pressure and $200^0$ F. It is equipped with a Lightnin model 14Q1, 1 hp vertical agitator with Hastelloy shaft and impeller for mixing during seeding (addition of calcium sulfate) and chemical cleaning operations. Suspended solids in the blowdown settle to the bottom of the tank where they are withdrawn by the underflow pump and transferred to the sludge holding tank for processing through the filter press. Clarified brine overflows from the product tank to the brine storage tank for export to market. The underflow pump is also used to transfer chemicals during seeding (addition of calcium sulfate) and chemical cleaning operations. A pulsation dampener is provided at the pump suction to minimize suction pressure surges during pump operation. The underflow pump is a Wilden model M4/HO/VT/VT/VT air-operated diaphragm-type with a Blacoh model 201V surge suppresser. The pump operates at 5 gpm and 45-ft TDH.

## PROCESS CONTROL SYSTEM

Process controls for the FGD plant are configured in a Westinghouse WDPFII distributed control system (DCS). The system consists of multiple distributed processing units connected through a redundant data highway to operation stations in the FGD control room and the main control room and to an engineer's station in the FGD control room.

The DCS has a modulating control subsystem for multiple analog control loops. Control loops, including cascaded loops, are controlled by redundant, dedicated microprocessor-based process controllers. Controllers provide bumpless transfer between control modes and bumpless automatic transfer from primary to secondary controllers upon controller failure. Controllers have redundant interfaces to the data communications subsystem. Controllers continue to function without interruption during communications subsystem failure. All control loops have anti-reset windup protection. Loops can be configured and tuned at the engineer's console. Configuration and tuning changes can be done on-line without causing process upsets. Controllers retain control configuration memory for at least 30 days following a total system power failure.

The DCS has a discrete control subsystem for control and monitoring functions associated with starting and stopping motors, opening and closing valves and dampers and interrogating various contacts throughout the FGD plant. This subsystem includes an alarm contact processing package. Alarm acknowledgment is available through all the consoles.

The DCS's operator interface subsystem includes multiple CRT/keyboard-based operator control consoles. Two dual-CRT operator consoles are located in the main control room, one dual-CRT operator console is in the FGD control room and one dual-CRT operator console is on the operating floor. There is also a single-CRT engineer's console in the FGD control room. The operator consoles are the primary operator interface with the FGD plant. All operator actions including discrete and modulating control, indication and process monitoring functions are handled through the consoles.

All FGD system equipment can be controlled in manual or automatic mode from any of the consoles. Motor start/stop and valve open/close functions are performed through the keyboard functions in concert with CRT touch screens. The subsystem provides easy operator access to all instantaneous and historical process information. All displays and data are common to all operator consoles and each console is adequate to properly control the process. All the functions of an operator console can also be performed through the engineer's console. In addition, the entire control system can be configured from the engineer's console. A 486-class PC, directly connected to the data highway, is capable of performing all engineering functions, backing up some operator functions and collecting and storing historical data as a backup to the main plant's VAX system.

The DCS has a plant monitoring subsystem for historic data storage and retrieval and miscellaneous data reporting and alarming functions. Three dot matrix printers, one in the main control room, one in the FGD control room, and one by the engineer console, provide printing of alarms, listings, reports and other text information.

The DCS communicates through its data highway subsystem. The control consoles are linked together through fiber optic cables. The DPU's which house the control system electronics are connected to the data highway through coaxial cables. The subsystem is fully redundant.

### 2.2.4 HEAT PIPE AIR PREHEATER

Originally, Unit 2 was equipped with two vertical flow Ljungstrom® air heaters. As part of the Milliken CCT-IV demonstration program, the Unit 2 Ljungstrom® units were replaced with two vertical flow heat pipes, provided by ABB Air Pre-Heater, to help overcome some of the boiler heat rate decline expected with the concomitant installation of low NOX burners and an FGD system. The CAPCIS corrosion monitoring system was to be used in conjunction with the high efficiency air heater system to control flue gas discharge temperature and prevent acid corrosion due to condensation.

#### MECHANICAL DESIGN

The design of the individual heat pipe air heaters is summarized in table 2.2-1. The general construction is schematically shown in figure 2.2-1 for the Unit 2A heat pipe. As indicated by the insert in figure 2.2-1, the Unit 2B heat pipe is constructed as a mirror image of Unit 2A. Each heat pipe contains 12 (3 horizontal - 4 vertical) shop-fabricated, heat transfer modules which are field assembled. To eliminate air leakage into the flue gas from the ambient environment or across the division wall between the air and flue gas sections, the modules are 100 percent seal welded. The box-shaped modules sit on duct transition sections which tilt the tubes $5^{o}$ above horizontal.

## TABLE 2.2-1
## HEAT PIPE AIR HEATER DESIGN SUMMARY
## NEW YORK STATE GAS AND ELECTRIC MILLIKEN STATION -- UNIT 2

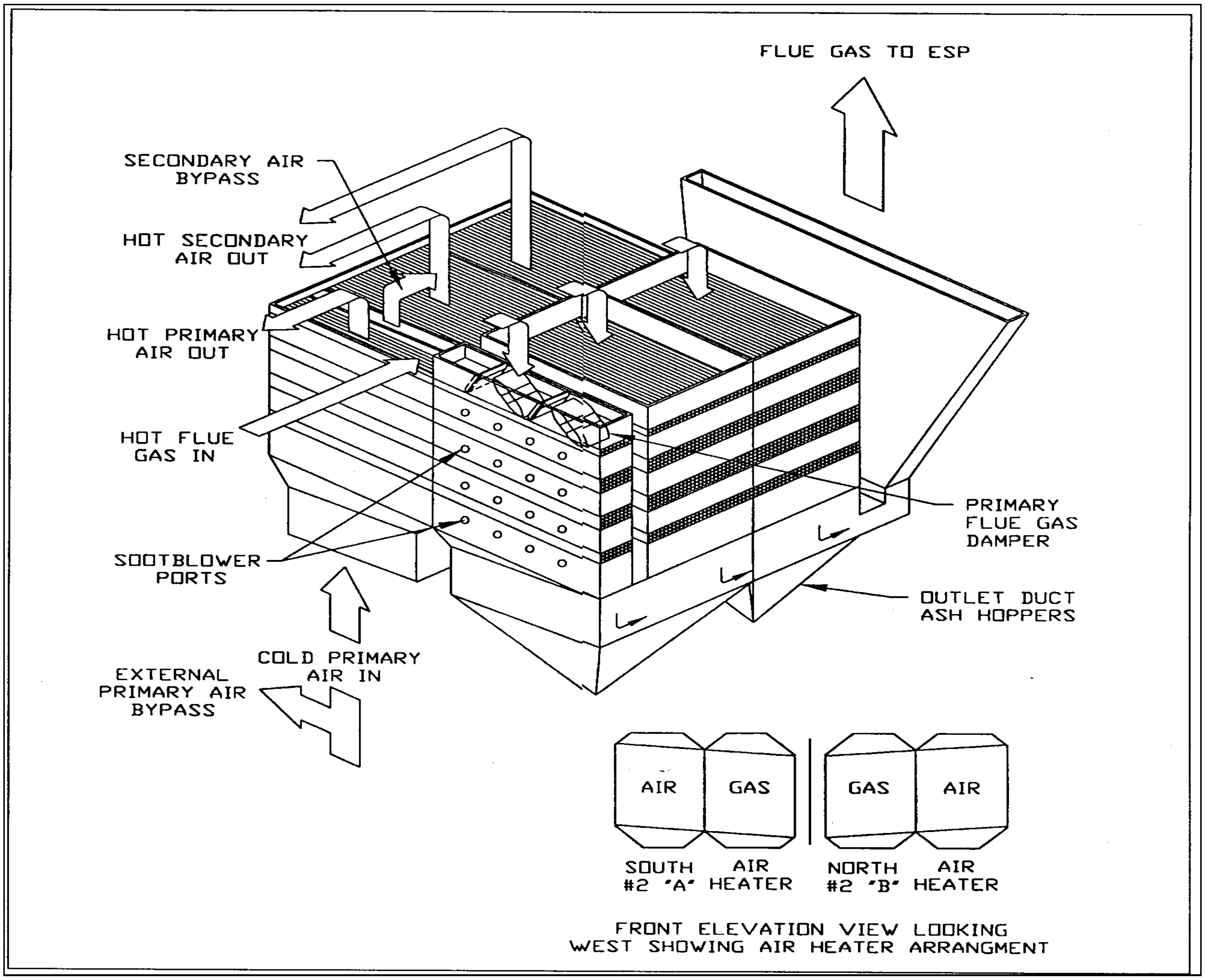
| | | |
|---|---|---|
| Manufacturer | ABB Air Preheater Inc. | |
| Model | 303.8-408-36-DV | |
| Number of Heat Pipe Air Heaters | 2 | |
| Number of Tube Modules/Air Heater | 3 Horizontal/4 Vertical | |
| Module Slope | 5$^0$ | |
| Tubes | | |
| Number | 2,880/ Heat Pipe | |
| Diameter | 2.0 in. | |
| Wall | 0.095 in. | |
| Pitch (triangular) | 3.75 in. | |
| Material | **Primary Sections** | **Secondary Sections** |
| | 7rowsTll CS | 1 row T11 CS |
| | 21 rows A-178A CS | 27 rows A-178A CS |
| | 8 rows A-618 CorTen A? | 8 rows A-618 CorTen A? |
| Working Fluid | 21 rows Naphthalene | 14 rows Naphthalene |
| | 15 rows Toluene | 22 rows Toluene |
| Fins | **Flue Gas Side** | **Air Side** |
| Type | Continuous Spiral | Segmented Spiral |
| Attachment | Welded | Welded |
| Height | 0.75 in. | 0.75 in. |
| Thickness | 0.059 in. | 0.036 in. |
| Density | 3 per in. | 7 per in. |
| Finned Length | ? ft | ? ft |
| Material | 28 rows A-178A CS? | 28 rows A-178A CS? |
| | 8 rows A-618 CorTen A? | 8 rows A-618 CorTen A? |

| **Design Performance (ea.)** | **Flue Gas Side (Combined)** | **Air Side Primary** | **Air Side Secondary** |
|---|---|---|---|
| Inlet Flow | 750,000 lb/hr | 62,500 lb/hr | 562,500 lb/hr |
| Inlet Temperature | 680$^0$ F | 80$^0$ F | 80$^0$ F |
| Outlet Temperature | 253$^0$ F | 650$^0$ F | 617$^0$ F |
| Specific Heat | 0.260 Btu/lb-$^0$F | 0.247 Btullb-$^0$F | 0.247 Btu/lb-$^0$F |
| Duty | 83.3 MM Btu/hr | 8.8 MM Btulhr | 74.5 MM Btu/hr |
| Minimum Cold Tube Temperature | | 221$^0$ F | 170$^0$ F |
| Guaranteed Pressure Drop | 3.65 in. WC | 3.60 in. WC | 5.35 in. WC |

The heat pipe tubes are 2” outside diameter (OD), 0.095” wall, and approximately 35.5 feet long. To achieve maximum heat transfer and compactness of design, the tubes are finned on both the flue gas and air sides and the tube rows are arranged on a 3.75” center-to-center staggered triangular pitch. On the flue gas side, 3/4” high continuous spiral fins (3/in.) are used. On the air side, 3/4” high segmented fins (7/in.) are used. The fins are attached to the tubes by a high frequency resistance welding process. The tube and fin materials of construction are carbon steel (CS) in areas where operating temperatures are above $300^0$ F and a low alloy corrosion resistant (LACR) material (CorTen A) in areas below $300^0$ F. Some T11, a low carbon, low alloy (1-1/4 chrome -1/2 Moly) CS, tube material is used in the highest operating temperature areas to reduce the potential of working fluid breakdown. The heat pipe casing is ASTM A36 mild CS since all flue gas side parts are expected to be at temperatures above the acid dew point.

**FIGURE 2.2-1**

**CONSTRUCTION OF MILLIKEN HEAT PIPE AIR HEATERS**



The heat pipe tubes are fixed only at the division wall. This allows the tubes to expand or contract as necessary. On the air side, the tubes expand within the exchanger case since the tubes are hotter than the combustion air being heated. On the flue gas side, the tubes contract within the case since the tubes are colder than the flue gas being cooled. A tube sheet is used to support the tube ends on the air side; while on the flue gas side, the lower tube ends are supported by short cylinder sleeves which are welded to the module walls.

The flue gas section casing is designed for -35 in. WC. The design pressures for the primary air and secondary air sections are ±60 in. WC and ±35 in. WC, respectively.

Each heat pipe exchanger weighs approximately 960,000 lbs. The exchangers are each supported on eight legs (not shown in figure 2.2-1) and are each anchored by one leg to the floor. The other seven support legs distribute the load and are free to move on sliding plate foot bearings. Four of the support legs are on guided foot bearings while the other three are on unguided free foot bearings. This design accommodates lateral movement due to thermal expansion or mechanical stress. The top of the heat exchangers are free to move and expand both vertically and horizontally. This movement is accommodated through the use of expansion joints on all ducts attaching to the air heaters.

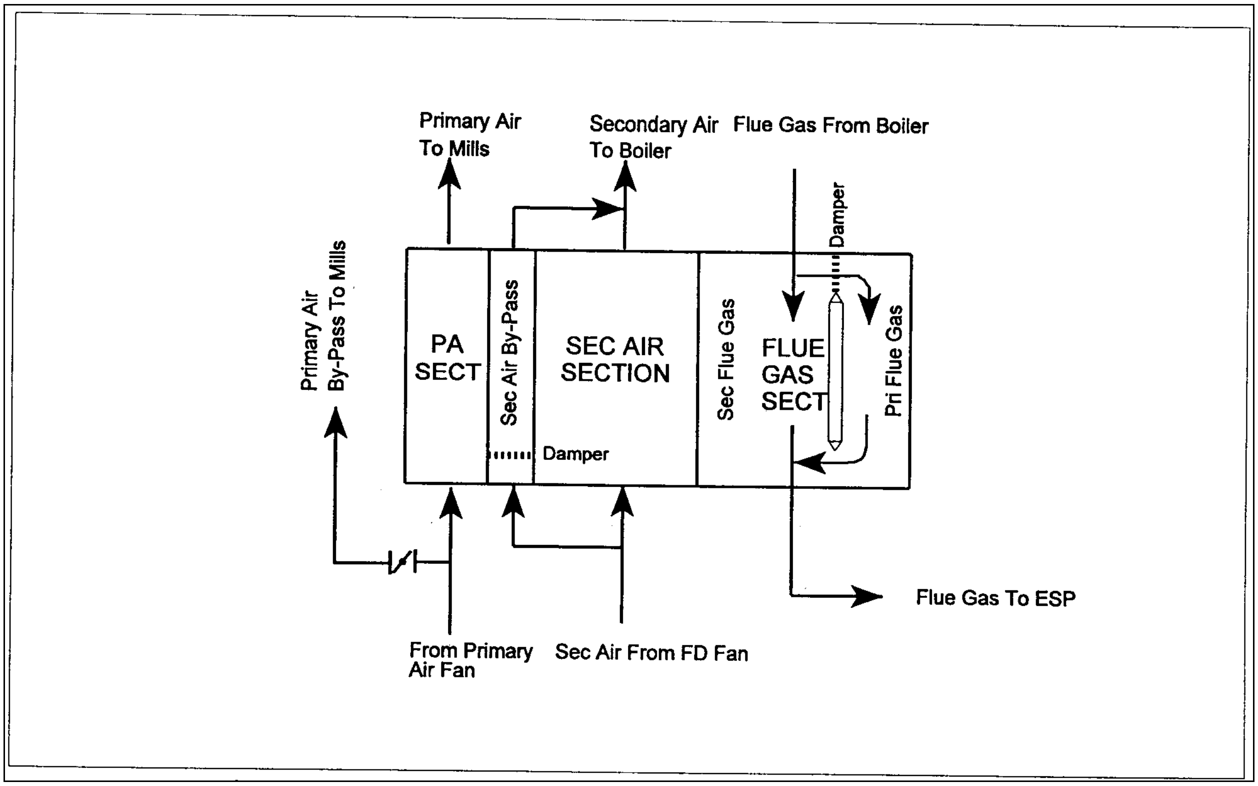
Each heat pipe exchanger is designed to heat both primary and secondary air streams in separate sections. This design provides added flexibility for coal drying and in achieving maximum heat recovery. Bypasses are provided for both the primary and secondary air streams. The primary air bypass is external to the heat pipe and is used to supply tempering air at the coal mills. The secondary air bypass is internal and an integral part of the heat pipe as shown in figures 2.2-1 and 2.2-2. An electrically driven damper inside the heat pipe (figure 2.2-2) is used to control the flow through the secondary air bypass. This bypass is used primarily to limit heat transfer from the flue gas section to avoid low cold-end tube temperatures which result in acid condensation. Under certain conditions, bypass control must be limited to prevent overheating of the hottest operating toluene filled tubes.

Two ducts from the boiler supply hot flue gases to the heat pipe air heaters, one duct to each air heater. The flue gases approach the air heaters through horizontal ducts. A set of ladder vanes inside the ductwork hood mounted on top of each heat pipe redirects the flue gas flow vertically downward to the heat pipe tube banks. The tube banks are split into one primary and two secondary flue gas sections. Gas distributes to the sections based on the pressure drop through the sections. When the air heaters were originally installed, the primary flue gas sections did not have inlet dampers. Louvered dampers were later installed by NYSEG to provide better temperature control and reduce the potential of overheating the hottest toluene filled tubes. Closing the dampers reduces the flow through the primary flue gas section and increases the flow through the secondary flue gas sections. However, primary flue gas flow adjustments have little effect on the overall secondary section flows since the primary gas flow is normally only about one-eighth the secondary flow.

On-line cleaning of the heat pipes is accomplished using sootblowers supplied with 150 psi air. There are 32 sootblowers, 16 on each air heater, which are located in lanes between the tube banks (figure 2.2-1). The bottom three tube banks can be cleaned on-line from both the top and bottom sides. There is provision to sootblow only the bottom of the top tube bank since the fly ash is dry at this location and little fouling is expected. Because of the large amount of sootblowing air required, a new air compressor was purchased and integrated into the existing plant air system. The new system uses a 3,000 acfm, 1200 hp, inter-cooled, three stage Ingersoll Rand centrifugal compressor.

**FIGURE 2.2-2**

**HEAT PIPE PROCESS FLOW STREAMS**



The sootblowers are retractable Bergemann units. The sootblowers have variable frequency gear motor drives which allow slower or faster blowing times depending upon the fouling conditions. When activated, the sootblower lances rotate in a helical fashion into the heat pipe to clean tube banks above and below the lance. Because of site access constraints, the sootblowers are equipped with lance tubes which are not fully retractable. When in the retracted position, the lance tubes extend half way across the heat pipe tube banks. The lances are equipped with two venturi nozzles at the tip end and two nozzles at the center. The two nozzles at each location are located

180$^{o}$ apart on the lance circumference. This design allows complete tube bank cleaning with a lance travel of one-half the cross section distance.

As shown in figure 2.2-1, there are solids collection hoppers directly under the flue gas side tube banks. The hoppers collect fly ash and sootblowing deposits which drop from the downward flowing flue gases as the gases change direction and flow to the outlet duct. Periodically, the hoppers are pneumatically emptied using the existing boiler/ESP pressurized ash conveying system.

## TEMPERATURE MEASUREMENT

Temperature measurement is key to analyzing performance and controlling the heat pipe air heaters. On-line measurements which are tied into the plant's computer data logging system fall into three categories: (1) flue gas and air temperatures to and from the heat pipes, (2) internal temperatures of critical tubes, and (3) tube skin and flue gas temperatures in the coldest tube row of the cold-end module. Because of high emf and linearity, chromel/constantan Type E thermocouples are used throughout. The ductwork close to the heat pipes is equipped with TC arrays for flue gas and air temperature measurement. All array TCs are contained within thermowells. The TC arrays provide information for calculating average temperatures and allow analysis of thermal performance based on changes in temperature gradient spreads. The TC arrays around each heat pipe are listed in table 2.2-2.

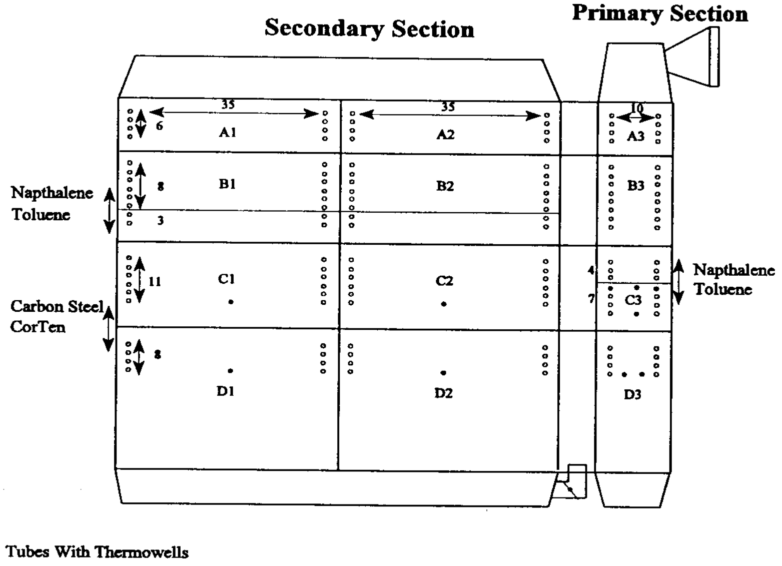
**TABLE 2.2-2**
**MILLIKEN HEAT PIPE FLUE GAS AND AIR STREAM TC ARRAYS**

| Stream | TC/Array |
|---|---|
| Flue Gas In | 10 |
| Flue Gas Out | 6 |
| Secondary Air Out | 6 |
| Secondary Air In | 4 |
| Primary Air In | 2 |
| Primary Air Out | 2 |

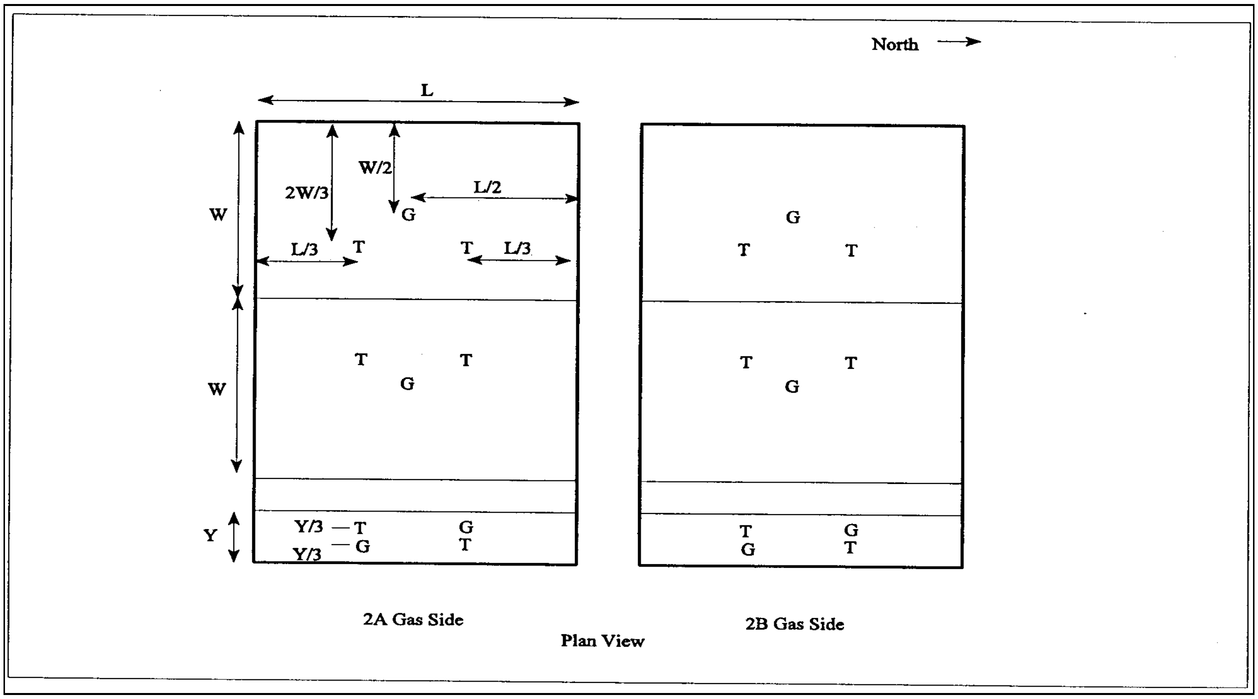
Each air heater is supplied with ten heat pipe tubes fitted with TCs within thermowells to measure temperatures in critical areas. Type E dual element (one active element plus spare) TCs are used. The thermowells are welded into evaporator end, end caps. This helps to insure accurate measurement of the tube operating temperature since the thermowells are surrounded by boiling liquid. Condenser end TCs are not used since inaccurate results would be obtained if non-condensable gases begin to buildup inside the heat pipes due to contamination or breakdown of the working fluids. The locations of heat pipes with thermowell TCs are indicated in figure 2.2-3. There are three TCs in the hottest row of toluene filled tubes (Module C3 of the primary air heating section). To prevent working fluid breakdown, the temperature of the toluene tubes must be limited to a maximum 550$^{0}$ F. Plant operators, therefore, monitor these

TCs to guide adjustment of the primary air rate through the air heater or the primary flue gas damper position. The other TCs are in areas where tube corrosion is a concern. Three TCs are located in the coldest CS heat pipes (last row of Modules Cl, C2, and C3) and four TCs are located in the cold-end heat pipes (last row of Modules Dl, D2, and D3).

**FIGURE 2.2-3**
**TUBE LAYOUT AND THERMOWELL LOCATIONS**
**FOR THE MILLIKEN HEAT PIPE AIR HEATERS**



## FIGURE 2.2-4
## COLD-END TUBE SKIN AND FLUE GAS TC LOCATIONS



After the air heaters were in operation, additional TC instrumentation was installed in the outlet cold-end modules to help monitor fouling behavior. Six heat pipe skin TCs were installed in each heat pipe air heater (figure 2.2-4). This was done by grinding the fins off a small area of a tube and then gluing a sheathed TC to the tube using a heat transfer cement. For comparison, four flue gas TCs were located near the skin TCs; two gas TCs in the primary flue gas section and two gas TCs in the secondary flue gas section. Monitoring of these TCs provided an on-line means of estimating where fouling was most severe in each heat pipe.

## STAGGERED TUBE DESIGN

In 1992, when inclusion of a heat pipe air heater was first proposed for the Milliken Unit 2 boiler, in-line tube arrangements were the common practice for finned tube preheaters. The in-line tube arrangement had proved to be a successful design which did not have problems with fly ash plugging or erosion. According to ABB Air Preheater Inc. (ABB/API), conventional sootblowing techniques were generally adequate to remove the slight plugging which occurred between tube rows. Staggered finned tube air heaters were normally not specified for coal fired boilers because of concern for potential increased plugging and fouling of tubes and fins and expected difficulties in cleaning. However, there was great interest in developing a successful staggered design. For the same heat transfer requirements, a staggered tube arrangement can result in a cheaper more compact design with fewer tubes due to the increased heat transfer afforded by the tortuous flow path. For the Milliken system design, a 35%

reduction in the number of heat pipe tubes was expected for the all staggered tube design over an all in-line tube design.

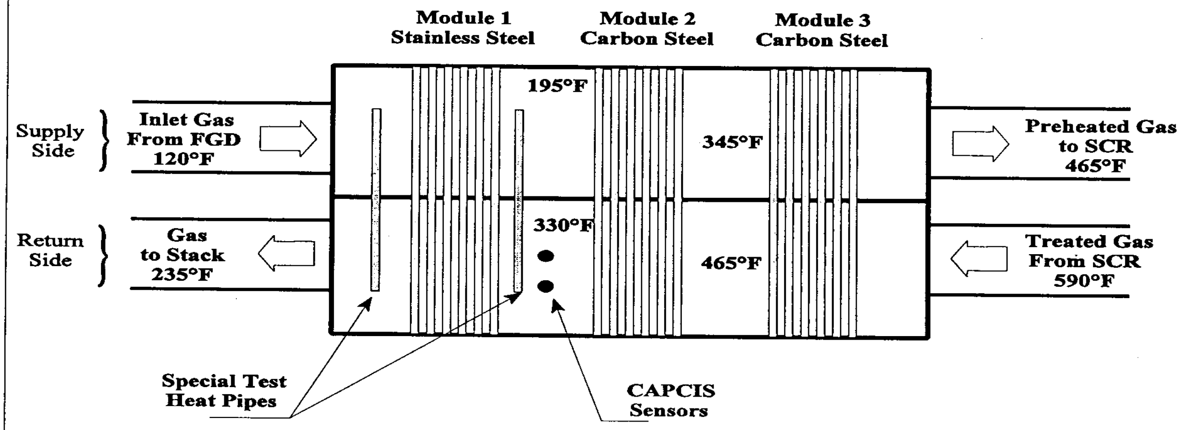
As part of a design effort, ABB/API installed a pilot heat pipe air heater at Milliken on a flue gas slipstream. The pilot heat pipe had removable tubes which could be rearranged with in-line or staggered tube pitches. Between October 6 to 27, 1993, ABB/API ran tests on the slipstream unit. The results indicated that a staggered, spiral finned design was practical and could be operated on a pulverized coal boiler without plugging. The testing also indicated that conventional sootblowing would be effective in cleaning the tubes and fins.

After the ABB/API test program was completed, NYSEG and CONSOL conducted separate tests to further establish operability of the staggered tube design in a boiler flue gas environment with and without ammonia slip from a $NO_X$ removal process. As part of this testing, parametric performance and long term operability tests were conducted without ammonia slip between October 27 and December 13, 1993. Cold-end tube temperatures were controlled at nominally $170^0$ F to simulate the operation of the commercial air heater with a $250^0$ F flue gas outlet temperature. This ensured that the cold-end tube metal temperatures were well below the flue gas acid dew point. The testing showed no fouling of the hot-end tube module and minor fouling of the cold-end tube module. The testing indicated that total flue gas side pressure drops might be expected to increase about 2.2 times the base drop over a six-month period. This was thought to be acceptable since the original pressure drop could be recovered by scheduled air heater washing every six months. The decision was made to install an all staggered tube design. As will be explained in Section 4.11, all tube bank modules but the cold-end module proved to be readily cleanable by sootblowing. The cold-end fouling however remains a major operating problem for the current heat pipe design.

## MATERIALS SELECTION

Heat pipe material selection was based on the results of corrosion test programs conducted at the EPRI Environmental Control Technology Center (ECTC) and at the NYSEG Milliken Station. The tests were primarily directed at evaluating construction materials for the cold-end modules of the commercial-scale heat pipe air heaters. In the cold-end modules, temperatures drop low enough for the small amount of $SO_3$ contained in the flue gases to react with water vapor and begin condensing as sulfuric acid. This can lead to severe fouling as fly ash/acid poultices form and acid attacks the heat transfer surfaces. Since testing of the selective non-catalytic reduction (SNCR) $NO_X$ removal process was originally proposed in the Milliken CCT-IV program, there were additional concerns for fouling and corrosion caused by the ammonia loss or slip from such processing. Leftover ammonia can lead to ammonium sulfate/bisulfate condensation in the air heater at temperatures higher than the $SO_3$ acid dew point. To address these issues, corrosion tests were initially conducted at the ECTC, and then later at Milliken Station.

## FIGURE 2.2-5
## PLAN VIEW OF ECTC HEAT PIPE HEAT EXCHANGER



The ECTC test facilities include a selective catalytic reduction (SCR) $NO_X$ removal pilot plant which has a small heat pipe heat exchanger. The exchanger is used to heat the $120^0$ F SCR reactor feed gas (flue gas from the Kintigh Station FGD) using the $590^0$ F reactor exit flue gas (figure 2.2-5). This exchanger provided an ideal location for testing candidate materials of construction in a fly ash-free environment with or without ammonia present. As shown in figure 2.2-5, test heat pipes made from CS, Cor-Ten® B, and AL-6XN® were installed (stacked vertically) at two locations. Since the cold-end module of the ECTC heat pipe contained 2,205 duplex stainless tubes with 409 stainless fins, information on these materials was also obtained. At the outlet of module 1 on the return side, the test heat pipes were exposed to the coldest cold-end flue gases with the highest potential for acid deposition. These heat pipes operated with metal surface temperatures between $150^0$ F and $210^0$ F which are well below the normal sulfuric acid dew point of $270^0$ F. At the inlet to module 1 on the return side, the test heat pipes were in an area where ammonia sulfate/bisulfate fouling was expected based on the previous operating history of the exchanger. Here the heat pipes operated with metal surface temperatures between $260^0$ F and $290^0$ F.

Although corrosion of the heat pipes was experienced on both the supply and return sides, only the return side corrosion will be discussed. This is the only area were the corrosion results are relevant to the design of the Milliken air heaters.

To monitor corrosion rates during individual tests, two electrochemical CAPCIS corrosion probes were installed on the return side between modules 1 and 2. One probe was made of SA-178A CS and the other from Cor-Ten® B. The probe instrumentation incorporates the use of electrochemical impedance measurement (ElM), electrochemical potential noise (EPN), electrochemical current noise (ECN), and zero resistance ammetry (ZRA). Changes in these electrical responses are used to determine the corrosion rate in real time and can be used to determine the type of attack (uniform or localized).

The ECTC test program consisted of operating the SCR heat pipe exchanger at design flow and temperature conditions with differing amounts of ammonia in the return side flue gas feed. To ensure constant ammonia slip conditions, the SCR was operated at zero ammonia slip with the required amount of ammonia injected separately downstream of the SCR reactor but ahead of the heat pipe inlet. Three test conditions were established, zero ammonia slip, 1-2 ppm ammonia slip, and *4-5* ppm ammonia slip. After each test period, the unit was shut down for inspection and cleaning of the heat pipe exchanger. The test heat pipes were installed in the ECTC heat exchanger in November 1992 and removed in May 1993. The total operating exposure to a flue gas environment was 3310 hours. After removal, the test heat pipes and one original heat pipe from the heat exchanger were destructively tested by ABB/API.

The general conclusion based on the destructive testing analysis was that none of the tested or original tube materials could provide a 20 year life for a cold-end tube bank for the ECTC heat pipe operating conditions and a standard tube wall thickness of 0.100”. The AL-6XN® was unsuitable since the material exhibited a marginal corrosion rate (5.3 mils/yr max.) at the location between modules 1 and 2, and localized pitting and cracking at the outlet of module 1 on the return side. At the module 1 outlet on the return side, the 409 SS fin material, CS, and Cor-Ten® B all exhibited high corrosion rates of up to 17.5 mils/yr for the 409 SS,42 mils/yr for the Cor-Ten® B, and 77 mils/yr for the CS. The Cor-Ten® B corrosion was relatively uniform as opposed to groove patterns associated with the corrosion of the CS. The groove patterns appeared to be due to liquid collecting on the tube surface with subsequent transport on and around the heat pipe. At the return side outlet of module 1, 2205 SS showed the lowest corrosion rates. However, the corrosion appeared to be flow related with the leading edge of the tubes showing more corrosion than the trailing edge, and there was evidence of anodic protection of the 2205 SS by the 409 SS fin material. For all materials, corrosion rates were lowest at the location between modules 1 and 2.

An internal air purge is used to control the sensing element temperature of the on-line CAPCIS corrosion probes independent of the flowing flue gas temperature. This feature allows the determination of specific conditions where the rate of corrosion becomes problematic. During the ECTC test program, corrosion rates were measured for SA-178A CS and Cor-Ten® B over a temperature range of about $100^0$ F to $230^0$ F. The data show a variation in corrosion rate with temperature. At temperatures below the water dew point (~$120^0$ F for the flue gas from the FGD), both materials show high rates of corrosion. From this point, the rates initially decline with increasing temperature to a minimum, then increase with increasing temperature to a second maximum, and finally decline again. For the CS probe, the second maximum occurred at about $160^0$ F regardless of the ammonia slip level while for the Cor-Ten® B material, the second maximum appeared to shift to higher temperatures with increasing ammonia slip. At zero ammonia slip, CS corroded more rapidly than the Cor-Ten® B. The presence of ammonia in the flue gases appears to reduce the corrosion rate for the CS (particularly at *5* ppm level) but increases the rate for the CorTen® B material.

The ECTC heat pipe environment is believed to be a worst-case test environment due to the high flue gas moisture (saturated with water at FGD outlet conditions) and the lack of any fly ash. High moisture levels increase the temperature at which $SO_3$ begins to condense and allows a more dilute, more corrosive acid to form. Operating without fly ash present results in the tube and fin metal surfaces being the only sites on which condensed acid can collect and react. With fly ash present, some of the acid would be sequestered by absorption on the ash or would be neutralized with alkalinity in the ash.

Based on the above, a decision was made to continue material selection testing at Milliken Station where tests could be conducted in a fly ash containing flue gas environment. Materials to be tested were: SA-178A CS, Cor-Ten® A, and 2205 duplex SS. These materials were selected because of cost and availability advantages for CS, the well known greater corrosion resistance of Cor-Ten® A over Cor-Ten® B, and the superior performance shown by 2205 SS in the ECTC tests. For the Milliken tests, the Cor-Ten® B CAPCIS corrosion probe was refurbished with Cor-Ten® A sensing elements and CONSOL R&D fabricated three “simple” air-cooled corrosion probes made from 2205 SS (one probe) and Cor-Ten® A (two probes). The simple corrosion probes were designed to simulate the operation of a heat pipe by maintaining constant corrosion coupon metal temperature using internal air purges. The simple probes had no electronic method for determining corrosion rates; rather the corrosion rates were determined by manual measurement of the probe outside diameters after exposure.

The Milliken corrosion testing was done in three stages. First, while the CAPCIS Cor-Ten® B probe was being refurbished, the SA-178A CS CAPCIS probe was installed at the outlet of the Milliken Unit 2 ESP. In this location ,the probe was exposed to a conventional flue gas environment but again without fly ash present. Over extended time periods, the probe was operated with sensing element temperatures of either $168^0$ F (1609 hours) or $231^0$ F (1501 hours). For the Milliken ESP outlet conditions, the electronically indicated corrosion rates were approximately 2 mils/year. These rates were confirmed by manual dimensional measurements which indicated somewhat lower average rates. These results indicated that CS was suitable for the ductwork and equipment downstream of the proposed air heater.

In the second stage of testing, the simple air-cooled corrosion probes were installed in the Unit 2 ESP inlet ductwork. At this location, the probes were exposed to a normal flue gas environment with fly ash present. The tests showed low corrosion rates (typically <3 mils/yr) for Cor-Ten® A regardless of the average targeted operating skin temperature (i.e., $172^0$ F, $192^0$ F, or $202^0$ F). However, the 2205 SS simple air-cooled probe showed severe pitting under fly ash scale buildups after only 832 hours of service at $170^0$ F surface temperature. This resulted in the 2205 SS being eliminated from further consideration as a construction material.

The third stage of testing included installing the SA-178A CS and Cor-Ten® A CAPCIS corrosion probes in the outlet duct of the ABB/API slipstream heat pipe. As mentioned above, ABB/API installed the slipstream heat pipe at Milliken to test the staggered tube design concept. After ABB/API completed this testing, NYSEG and CONSOL R&D took over operation and installed a pilot SCR reactor ahead of the test heat pipe. This afforded heat pipe testing in a flue gas environment with fly ash and ammonia present. The results indicated that the fly ash provided some protection against $SO_3$ and/or ammonium bisulfate ($NH_4$ $HS0_4$ ) attack. Overall corrosion rates for both metals were low i.e., 2.9-3.5 mils/yr for CS at $176^0$ F and <2mils/yr for Cor-Ten® A at $174^0$ F. Corrosion rates did not appear to depend on the ammonia slip between 1 and 3.5 ppm slip. Based on these results and all the previous corrosion test work, the decision was made to use CS for heat pipes operating above $300^0$ F skin temperature and Cor-Ten® A for all heat pipes operating below $300^0$ F skin temperature.

## INSTALLATION -- EQUIPMENT LAYOUT

An important goal of the Unit 2 equipment design was to install $SO_2$ and $NO_X$ control systems with minimum impact on the overall plant heat rate. Therefore, energy technologies such as the use of a heat pipe air heater were integrated into the plant design. The heat pipe was designed for a minimum 20 $^0$F decrease in the flue gas side air heater outlet temperature. This was expected to provide an approximate 0.5% improvement in heat rate. The no air leak feature of the heat pipe was expected to reduce air flows by about 16% and save approximately 337kW of fan power.

Because the Unit 2 air heater and coal mills were being replaced at the same time, there was an opportunity to reconsider the design of the primary air supply/coal mill circuit to further reduce power requirements. Two concepts were considered: the use of a single sector air heater coupled with four hot primary air fans (one fan to each mill), or, separation of the primary and secondary air heating sections and the use of two cold primary air fans (one supplying each air heater). The decision was made to install the cold primary air fan system since analysis of the concept indicated reduced construction and capital equipment costs, lower projected maintenance costs, and a 20 Btu/kWh power savings.

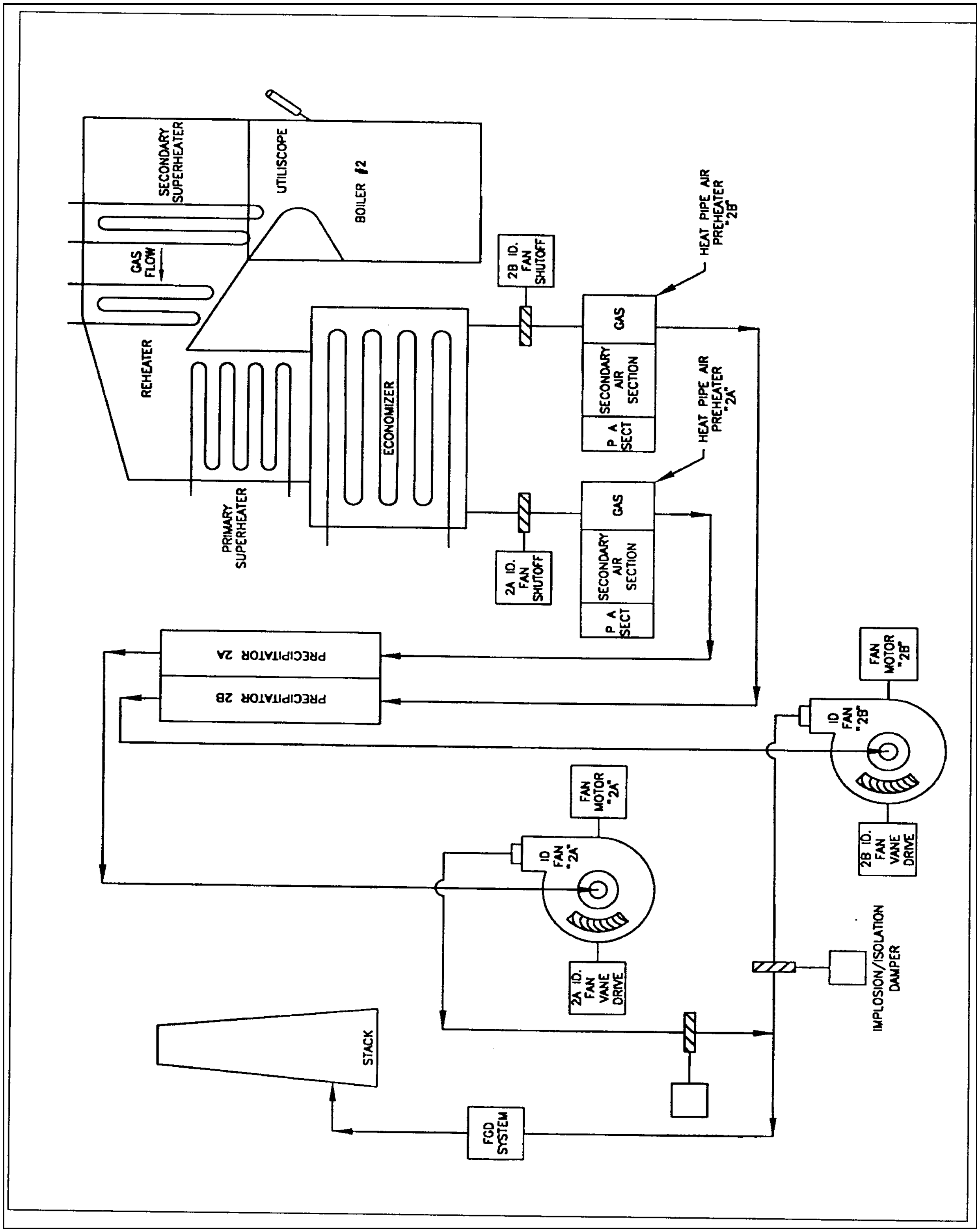
The overall process flow scheme is presented in figures 2.2-6, 7, and 8. Figure 2.2-6 shows the flue gas loop with hot gas from the boiler economizer passing through the heat pipe. The hot flue gases heat the primary air and secondary air streams in separate compartments in the air heater. From the air heaters, the cooled flue gases then proceed on to the ESP particulate collectors, ID fans, FGD, and finally the stack.

Figure 2.2-7 shows the primary air circuit to the coal mills. High pressure primary air is supplied by a cold PA fan to the air heater. Heated primary air streams from the two air heaters combine in a common header which splits into four coal mill feed streams. Bypassed tempering air mixes with the heated air ahead of each mill. The flows of hot primary air and tempering air are blended as required by mill load and coal dryness.

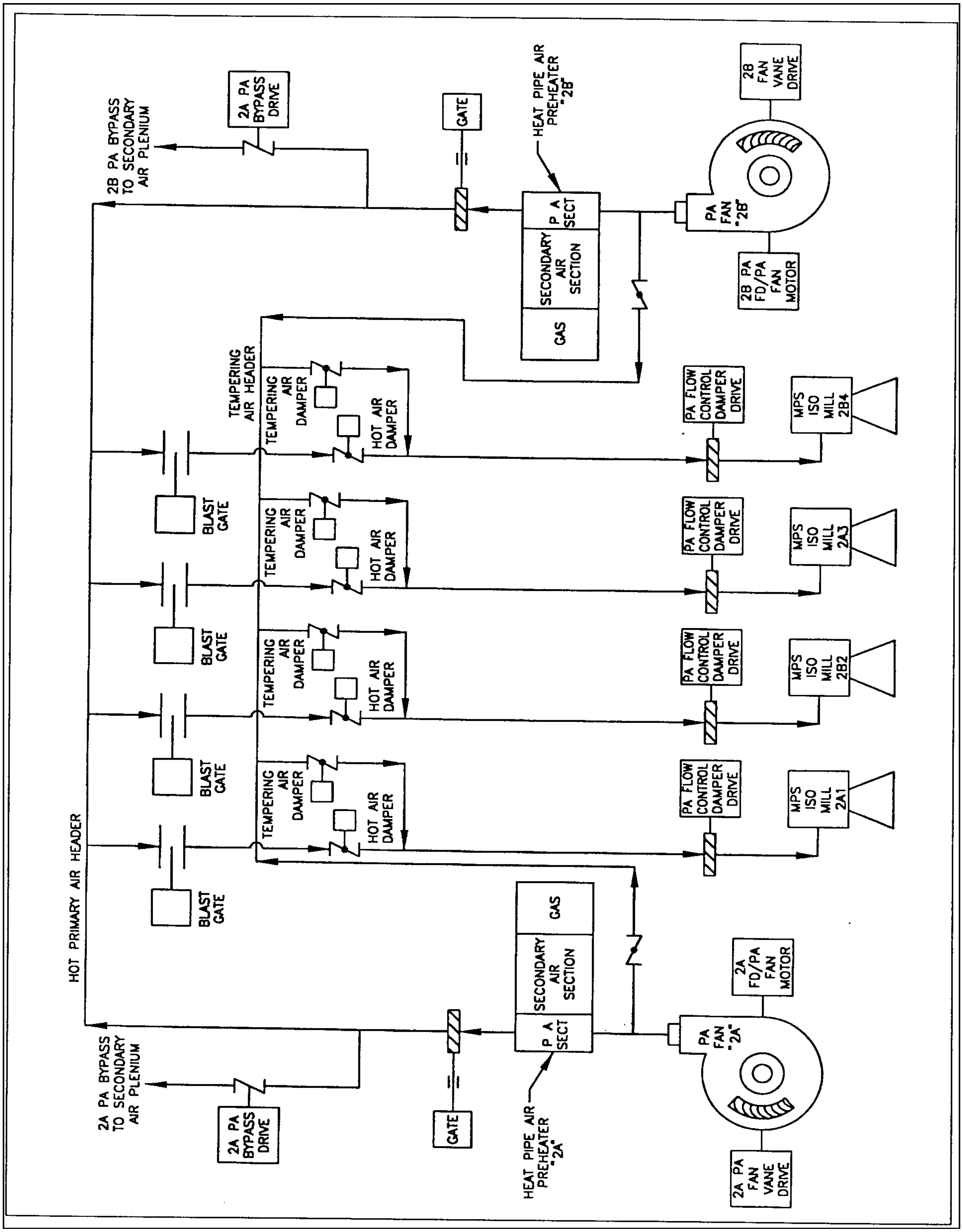
The secondary air system is shown in figure 2.2-8. A low pressure forced draft (FD) fan supplies the air to the secondary air heating section of the air heater. The heated air then flows to the boiler burners. Normally all the required secondary air flow passes through the air heater. A bypass is provided to help control the flue gas outlet temperature. This prevents operating the cold-end heat pipe tubes at too low a temperature which would result in excessive fouling.

Figures 2.2-9 to 12 show the final equipment layout. Because the heat pipes were located under the precipitator, the old Ljungstrom® air heaters were left in place. The inlet vertical ductwork to the Ljungstroms® was disconnected and new horizontal ducts to the heat pipes installed as shown in figure 2.2-9. There are ash hoppers under the flue gas sections of the air heaters to collect sootblown ash agglomerates. The cooled flue gases leave the bottom west side of the air heater, travel vertically up to a crossover duct, which leads to another vertical flow duct to the precipitator entrance. Leaving the precipitator, the flue gases flow down to the induced draft (ID) fan at grade level.

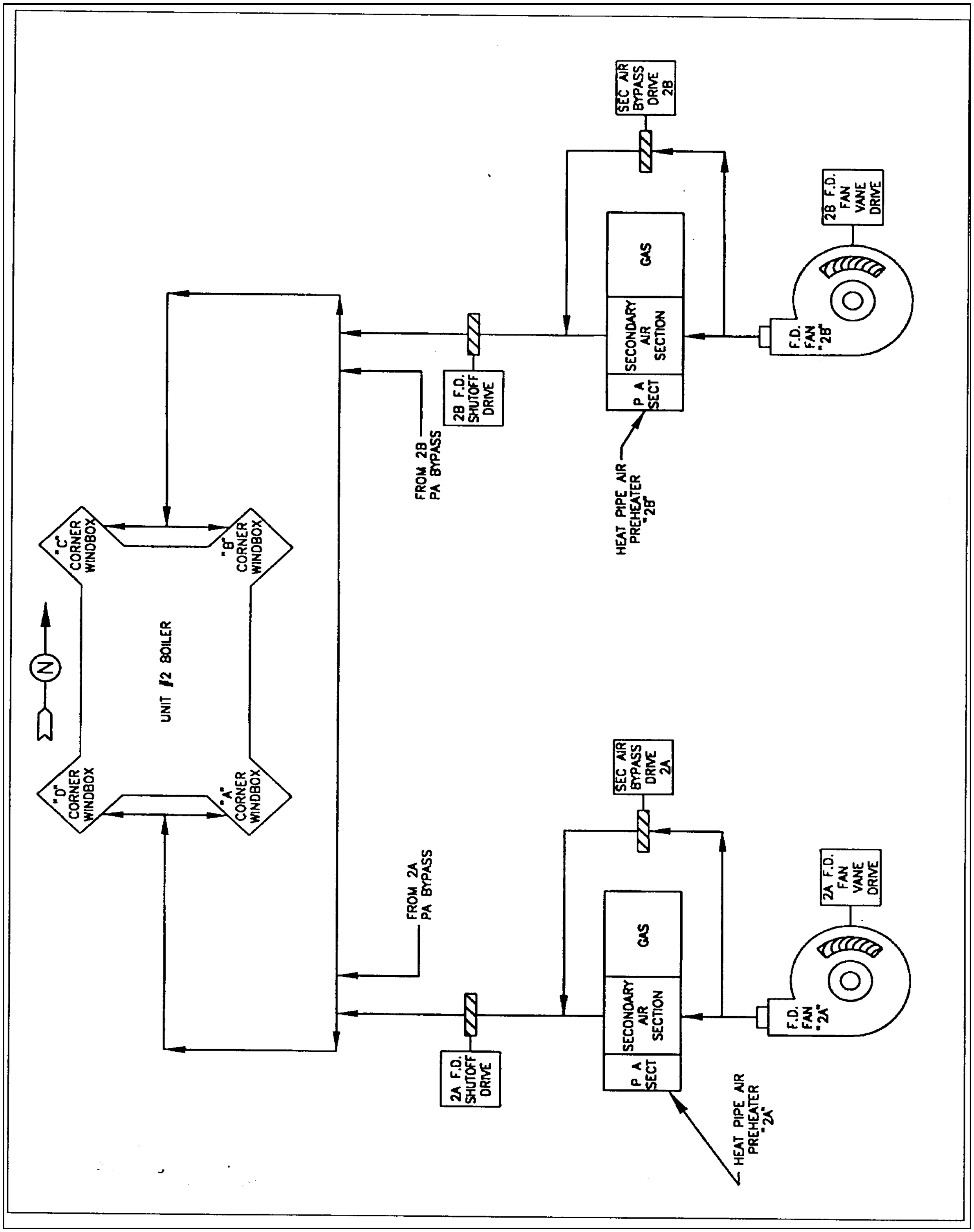
## FIGURE 2.2-6
## UNIT 2 INDUCED DRAFT SYSTEM



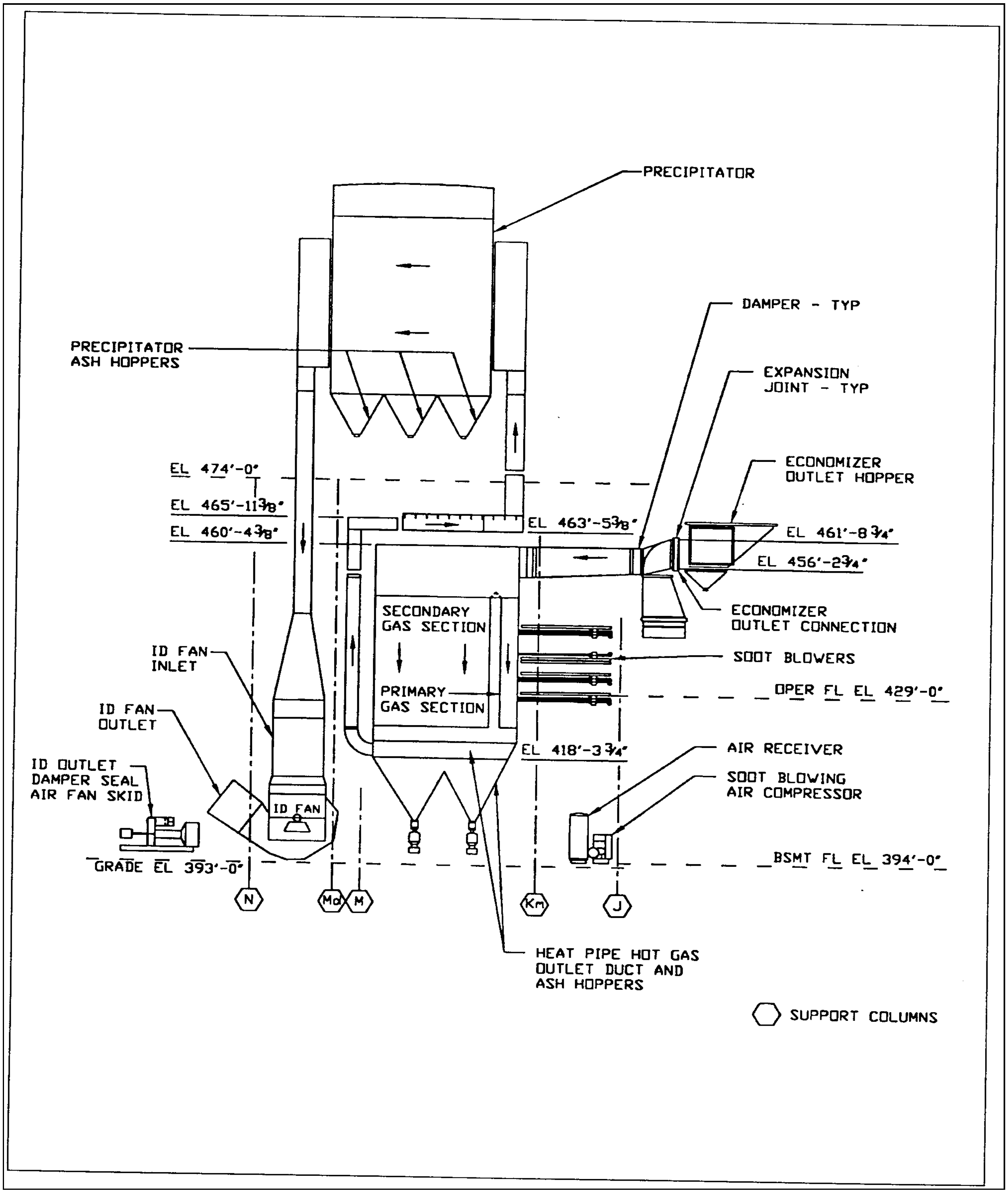
## FIGURE 2.2-7
## UNIT 2 PRIMARY AIR SYSTEM



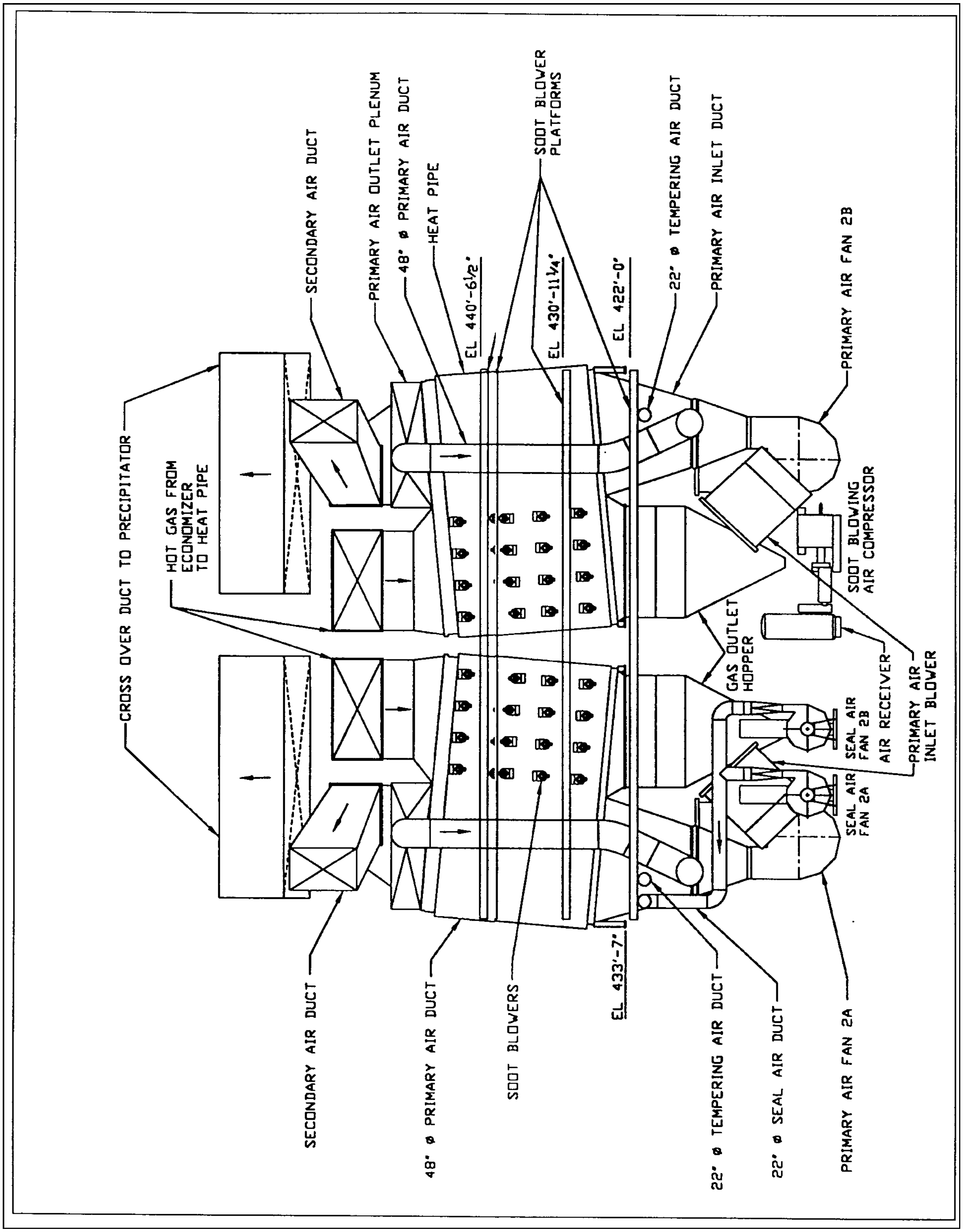
## FIGURE 2.2-8
## UNIT 2 FORCED DRAFT (SECONDARY AIR) SYSTEM



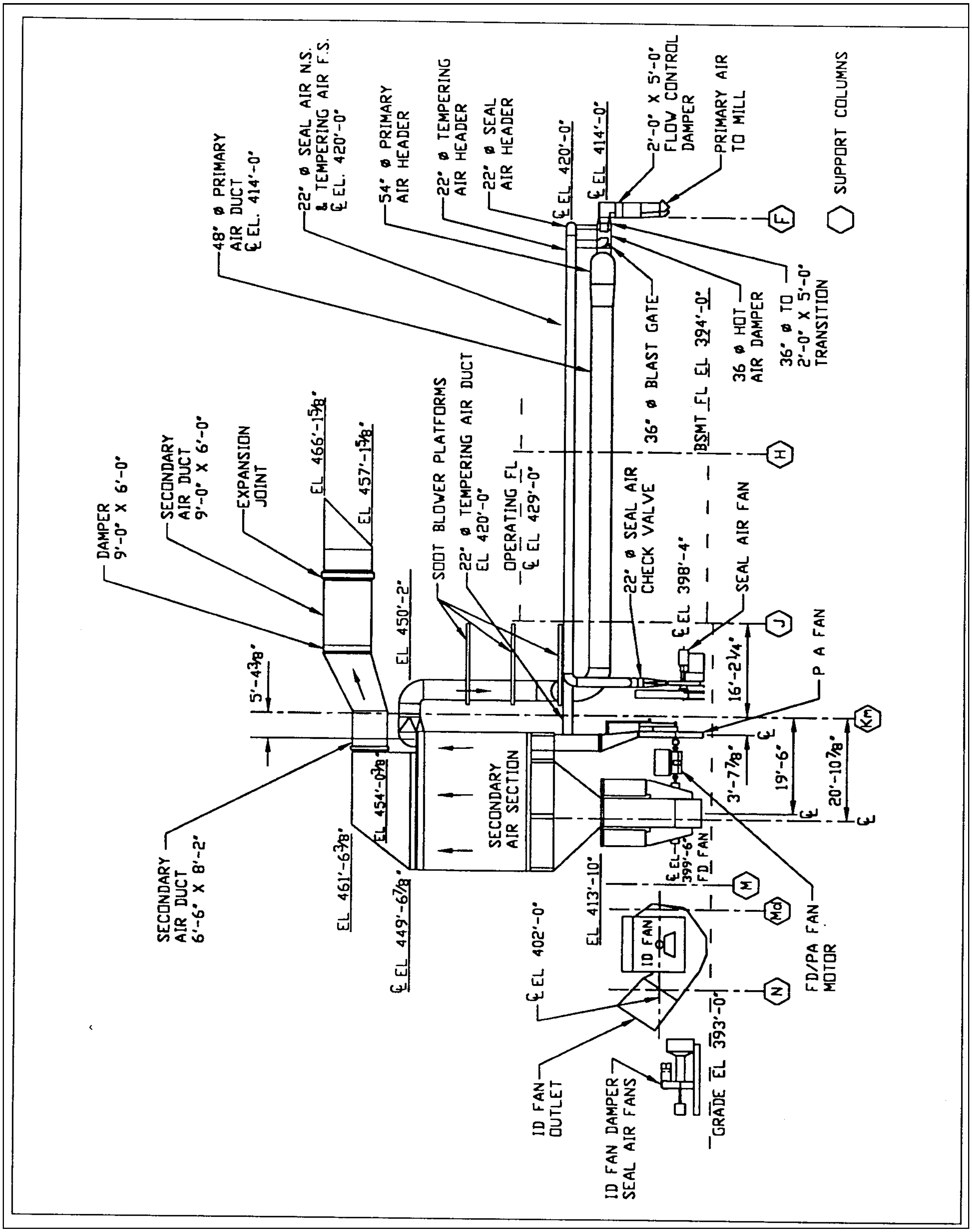
## FIGURE 2.2-9
## HEAT PIPE EQUIPMENT LAYOUT – FLUE GAS SECTION



## FIGURE 2.2-10
## FRONT VIEW (LOOKING WEST) OF HEAT PIPE AIR HEATERS



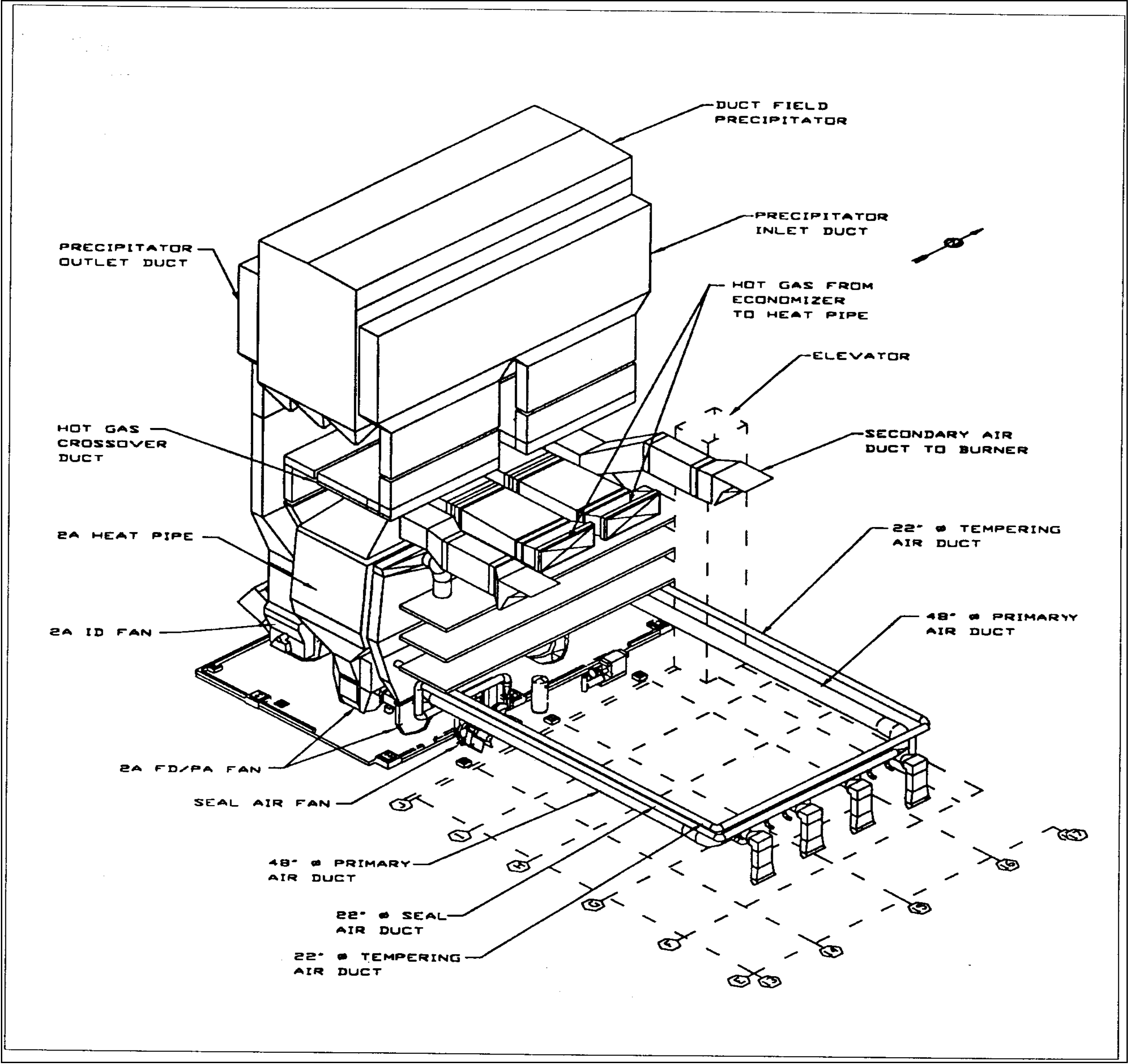
## FIGURE 2.2-11
## VIEW (LOOKING NORTH) OF HEAT PIPE AIR SECTIONS



A front facing east side view of the system is presented in figure 2.2-10. The view shows the locations of the primary air fans, sootblowing air compressor, mill seal air fans and the 32 sootblowers.

Figure 2.2-11 is a northward facing view of the unit showing the primary and secondary air duct system. The view shows the PA and FD fans and the common motor. Placing the PA and FD fans directly below the heat pipes allows use of short expanding ducts between the fan discharges and the heat pipe connection flanges. An isometric view of the system is presented in figure 2.2-12.

**FIGURE 2.2-12**
**ISOMETRIC VIEW OF HEAT PIPE AIR HEATER AND DUCTWORK**



## FLOW MODELING

A major goal of the test program was to operate the heat air heaters at the lowest possible outlet temperature consistent with low tube corrosion. Achieving a uniform flue gas distribution in the air heater is critical in limiting the development of cold gas spots. To help insure optimum equipment performance, flow model testing of the heat pipe and ductwork was performed. This allowed optimizing the gas/air flow profiles in the heat pipe and ductwork and minimizing ductwork pressure drops. The model test results were incorporated into the final full-scale ductwork design.

Fluid Systems Engineering Incorporated, of Parsippany, New Jersey conducted the flow testing in a dimensionally correct, 1/12 scale, cold-flow model of the heat pipe and ductwork. The model was fabricated from 1/4” thick clear Plexiglas with turning vanes made from thin 24 gage galvanized sheet steel. The heat pipe bundles were simulated using perforated plates within the heat pipe cases. On the flue gas side, the ductwork included all the ducting between the economizer outlet to the heat pipe inlet and all the outlet ductwork from the heat pipe outlet to the vertical riser duct at the ESP inlet (see figure 2.2-9). On the air side, the ductwork included all ducting from the FD fan discharge to the heat pipe and all the secondary air ductwork from the heat pipe to the boiler (see figure 2.2-11).

Flue gas and air flows through the full-scale prototype heat pipe system were simulated by drawing ambient air through the scale model using a laboratory fan. Air rates were $(1/12)^2$ i.e., (1/144) the full-scale design rate. This insured turbulent conditions in the scale model and provided a 1:1 velocity ratio between the full-scale prototype unit and the scale model. The use of a 1:1 velocity ratio coupled with geometric similarity with the full-scale unit, allowed the model to be used effectively in flow evaluations and correction of distribution problems. The use of cotton streamers and smoke observations allowed visualization of flow through the unit. Pitot and hot-wire anemometer measurements were used to quantify velocity profiles within the ductwork and in the heat pipe. Fly ash fallout in the ductwork was simulated with fine silica test particulate.

The model testing achieved the following:

- Developed flue gas side inlet duct vane and inlet hood ladder vane designs which provided uniform flow distribution at the heat pipe entrance and within the tube banks. The design resulted in a very good velocity distribution in the center of the tube banks with a root-mean-square (RMS) deviation of only 7.63%.
- Developed a FD fan discharge ductwork vane splitter design which improved the secondary air flow distribution to the heat pipes. The design achieved an acceptable 25.2% RMS velocity distribution in the center of the heat pipe tube banks. Additional testing indicated that inclusion of perforated plates in the inlet ductwork would further improve the air flow profiles. These plates were later installed following the initial operation of the full-scale air heaters.

- Developed a design for the high baffles of the heat pipe bottom ash hoppers which minimized flow scouring in the hoppers so that the hoppers acted as an effective dropout zone for fly ash.
- Optimized the design of the flue gas outlet duct turning vanes to establish a desired gas flow profile to the ESP particulate collector.
- Optimized the flue gas outlet crossover duct roof baffle design to eliminate solids dropout accumulations.
- Developed air side outlet hood and outlet ductwork vane designs which minimized pressure drop and achieved uniform flow distribution.

### 2.2.5 NALCO FUELTECH $NO_x$OUT® SELECTIVE NON-CATALYTIC REDUCTION

As originally proposed the MCCTD project included combustion modifications for primary $NO_X$ emissions control and Nalco Fuel Tech's $NO_X$OUT® selective non-catalytic reduction system (SNCR) to further reduce $NO_X$ emissions while retaining flyash salability. The $NO_X$OUT® process provides reduction in $NO_X$ through reaction with urea injected into the post-combustion zones of the boiler. The equipment required to deliver the chemical to the injectors is designed based on the specific range of flowrates required, the nature of the control system desired, the amount of air required for atomization and any local construction codes. A modularized approach is used in which the overall delivery system is broken down into five specific segments: storage, recirculation, metering/mixing, distribution and injection. The $NO_X$OUT® process includes:

- Proprietary computer codes to ensure that the $NO_X$OUT® chemicals are optimally distributed in the boiler.
- Control hardware and software to enable the $NO_X$OUT® process to follow boiler load changes by altering the flow rate and injection point of the urea-based reagents.
- Chemical feed, storage, mixing, metering, and pumping systems.

The $NO_X$OUT® demonstration was eventually relocated to GPU's Seward Station. A description of the Seward demonstration facilities was not available at the time of publication of this report and will be included in a future topical report.

## 2.3 PROPRIETARY INFORMATION

This section summarizes protected and proprietary information for Saarberg-Hölter Umwelttechnik, the Stebbins Engineering and Manufacturing Company, Nalco Fuel Tech, ABB Air Preheater and New York State Electric & Gas Corporation. In addition, other equipment vendors have identified their piping and instrumentation drawings (P&ID) and process flow diagrams (PFD) as proprietary. These vendors include; RCC and IDI (waste water treatment suppliers.)

Saarberg-Hölter Umwelttechnik has identified the following as proprietary:

- S-H-U/NYSEG contract
- Liquid-to-gas ratio specific to the Milliken design.
- Amount of recycle slurry i.e., flow rate.
- Oxidation air ratio or oxidation air rate.
- Gas velocities and residence time within critical regions of the absorber. Critical regions are defined as the transition zone between cocurrent and countercurrent sections and the slurry contact zone between the cocurrent spray header and the countercurrent outlet header. The total residence time will be provided.
- Slurry distribution to each spray level or nozzle.
- Concentration of formic acid in recycle slurry.
- The method of using the quench to control formic acid consumption rate.
- The number and type of spray nozzles per level; however, the total number, type and material of construction for slurry nozzles will be provided.
- The process dewatering details i.e., PFD with detailed mass balance.
- Detailed mass balances for internal scrubber process streams. This includes gypsum dewatering and absorber systems.
- Detailed drawings of absorber internals.

Stebbins Engineering and Manufacturing Company has identified the following as proprietary:

- Stebbins/NYSEG contract.
- QA/QC Manual (includes installation techniques, maintenance techniques and mixing instructions.)

- Material formulas/compositions.
- Insert/nozzle placement details.
- Rebar placement details.
- Design of wall/cover details.
- Concrete mix composition/design.
- Specific cost of items.

Nalco Fuel Tech has identified the following as proprietary:

- Nalco Fuel Tech/NYSEG contract.
- The computer program and the results of Nalco Fuel Tech's fluid dynamic modeling of the Milliken Station boiler.
- The computer program and results of Nalco Fuel Tech's Kinetic modeling of the Milliken Station boiler.
- The formula or composition of chemical reagents supplied by Nalco Fuel Tech.
- The design and material of construction of the chemical injection equipment.

ABB Air Preheater, Inc. has identified the following as proprietary:

- Heat pipe fill fluid quantities/calculations.
- Performance calculations and computer programs.
- Shop fabrication procedures and detailed shop drawings.
- QA/QC manuals/records.
- Equipment pricing/costing data (audit reports).
- General arrangement drawings.
- Field installation drawings.
- Contract terms and conditions/warranties/guarantees.

New York State Electric & Gas Corporation identifies all of its contracts with participants and co-funders as proprietary information.

## 2.4 SIMPLIFIED PROCESS FLOW DIAGRAMS

A block flow diagram for the entire MCCTD project is presented in FIGURE 2.4-1. Selected areas of the system are detailed further in additional flow diagrams as follows:

- Process Block Flow Diagram
  FIGURE 2.4-1

- Limestone Preparation Flow Diagram
  FIGURE 2.4-2

- S-H-U Flow Diagram
  FIGURE 2.4-3

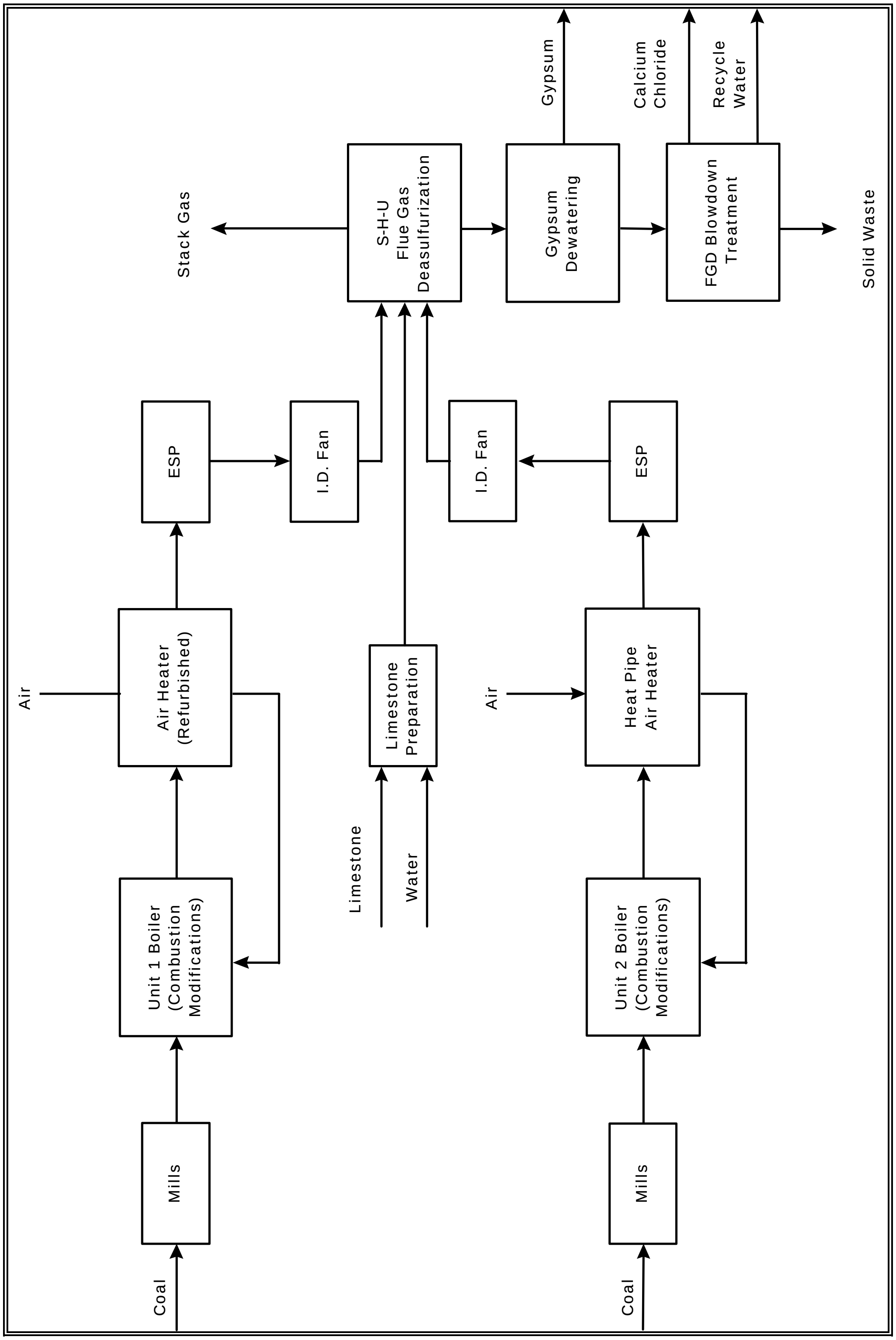
- FGD Wastewater Pretreatment System Flow Diagram
  FIGURE 2.4-4

- FGD Wastewater Brine Concentration System Flow Diagram
  FIGURE 2.4-5

- $NO_X$OUT® Flow Diagram
  FIGURE 2.4-6

- Heat Pipe Air Heater Flow Diagram
  FIGURE 2.4-7

## FIGURE 2.4-1
## PROCESS BLOCK DIAGRAM FOR MCCTD PROJECT



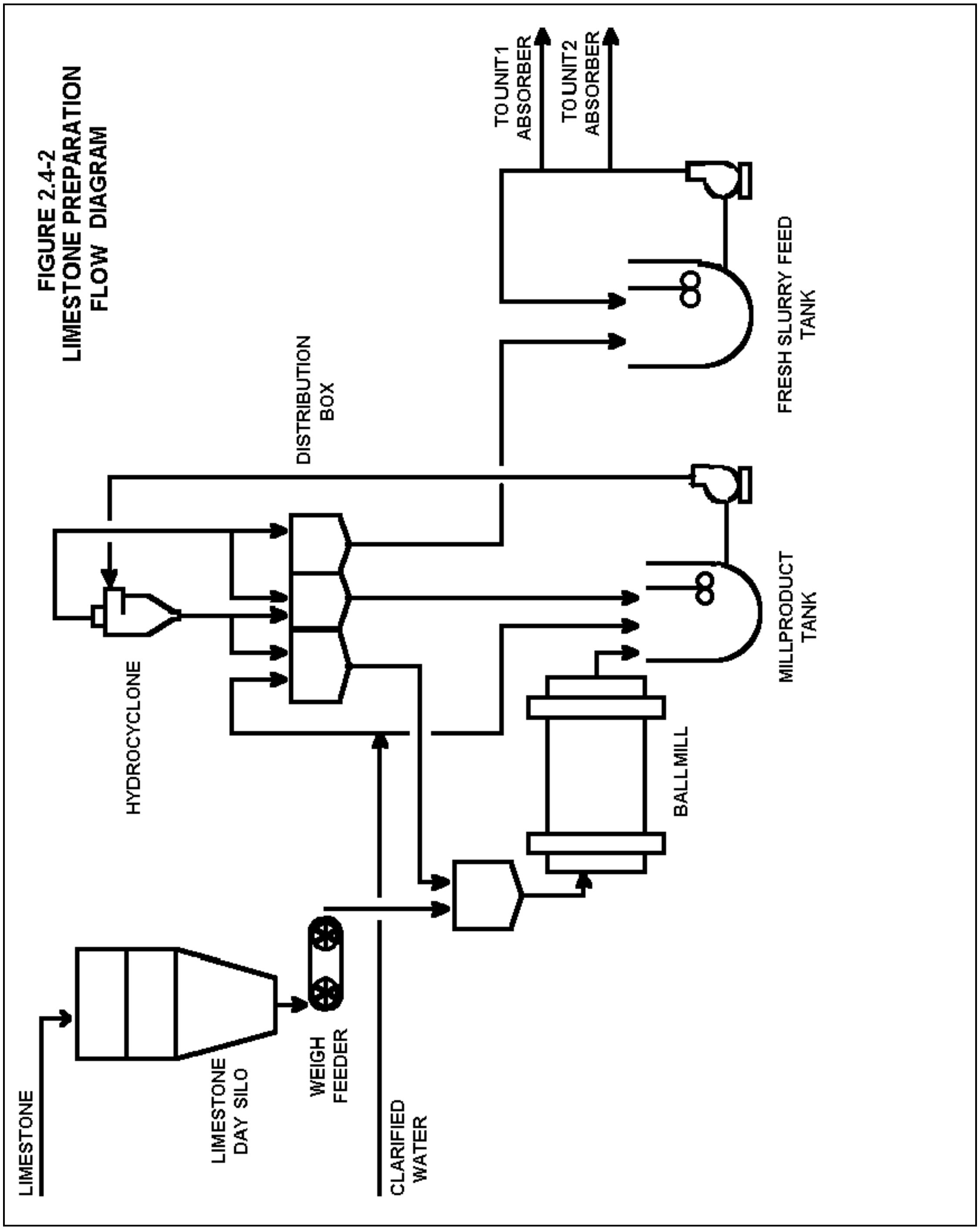
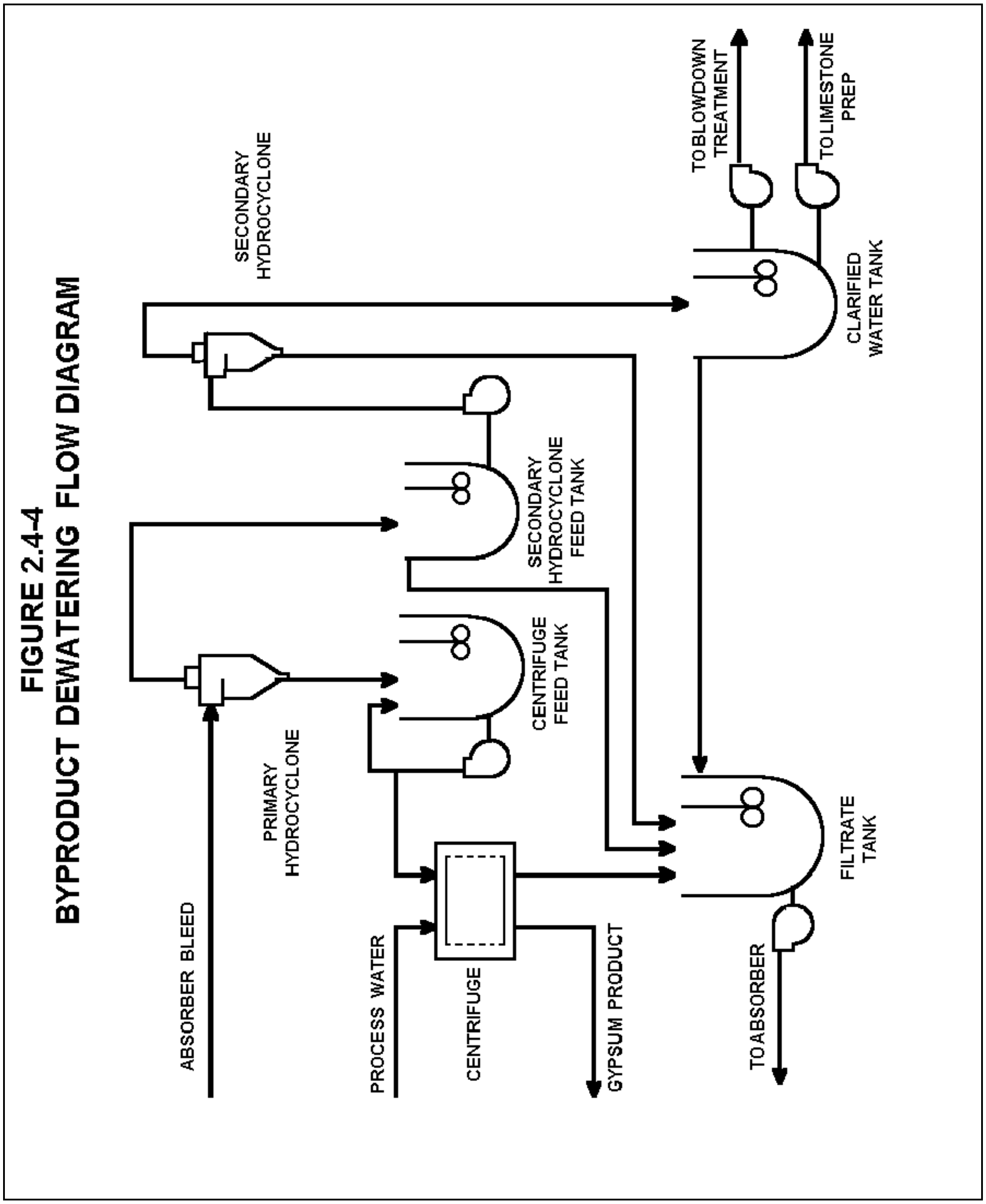


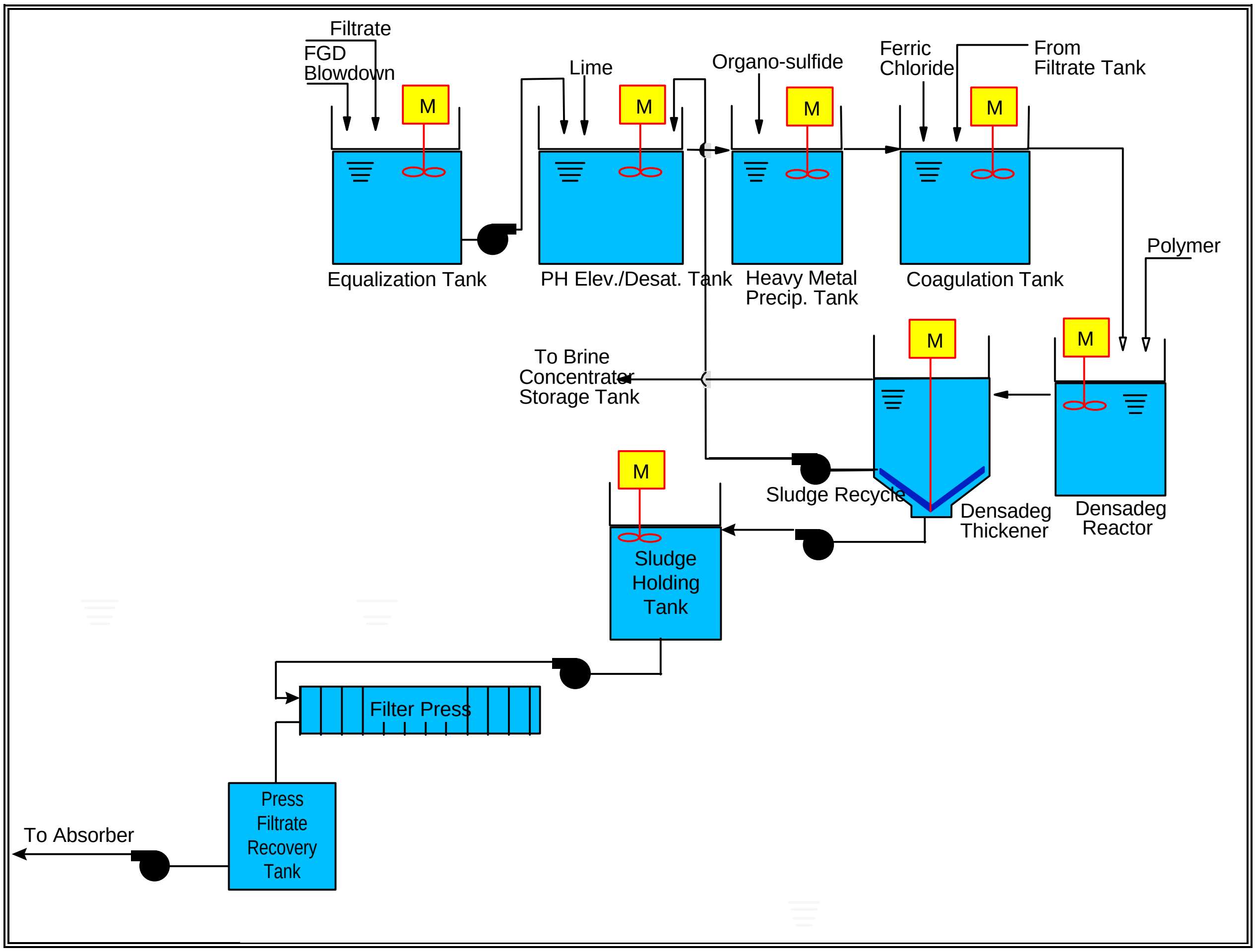
FIGURE 2.4-2
LIMESTONE PREPARATION
FLOW DIAGRAM

## FIGURE 2.4-3
## S-H-U FLOW DIAGRAM



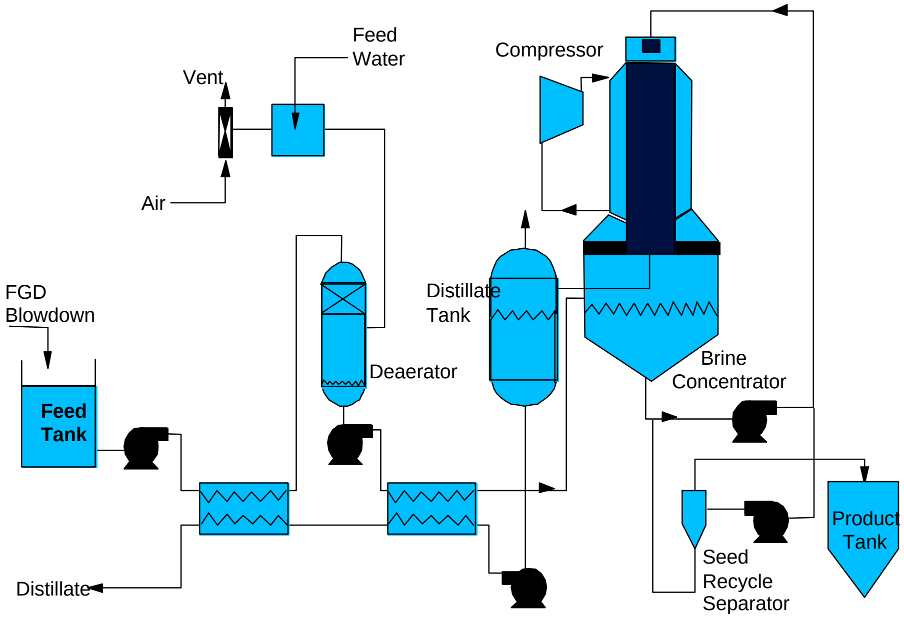
# FIGURE 2.4-4

# FGD WASTEWATER PRETREATMENT SYSTEM FLOW DIAGRAM

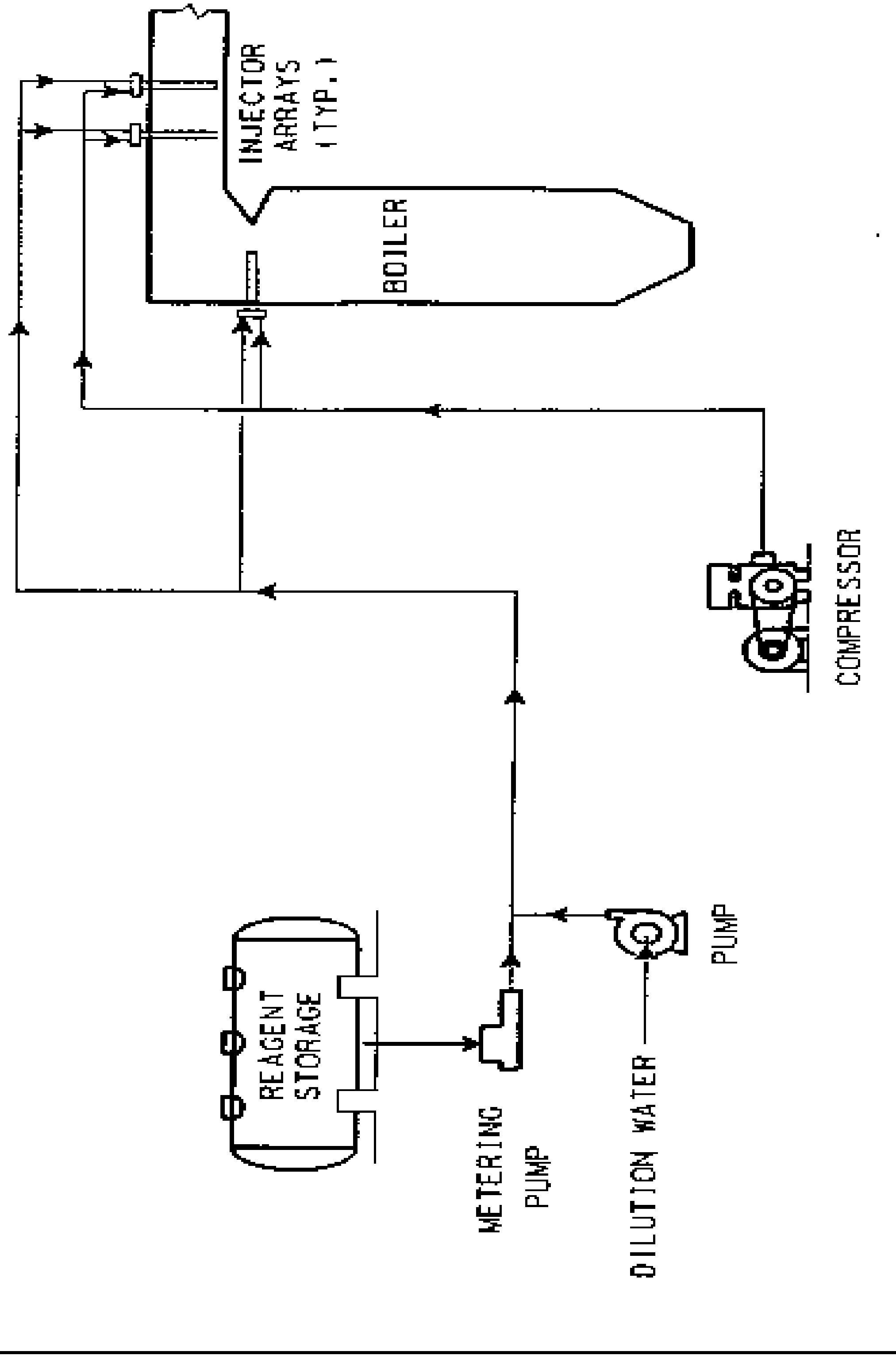


# FIGURE 2.4-5

# BRINE CONCENTRATION SYSTEM FLOW DIAGRAM

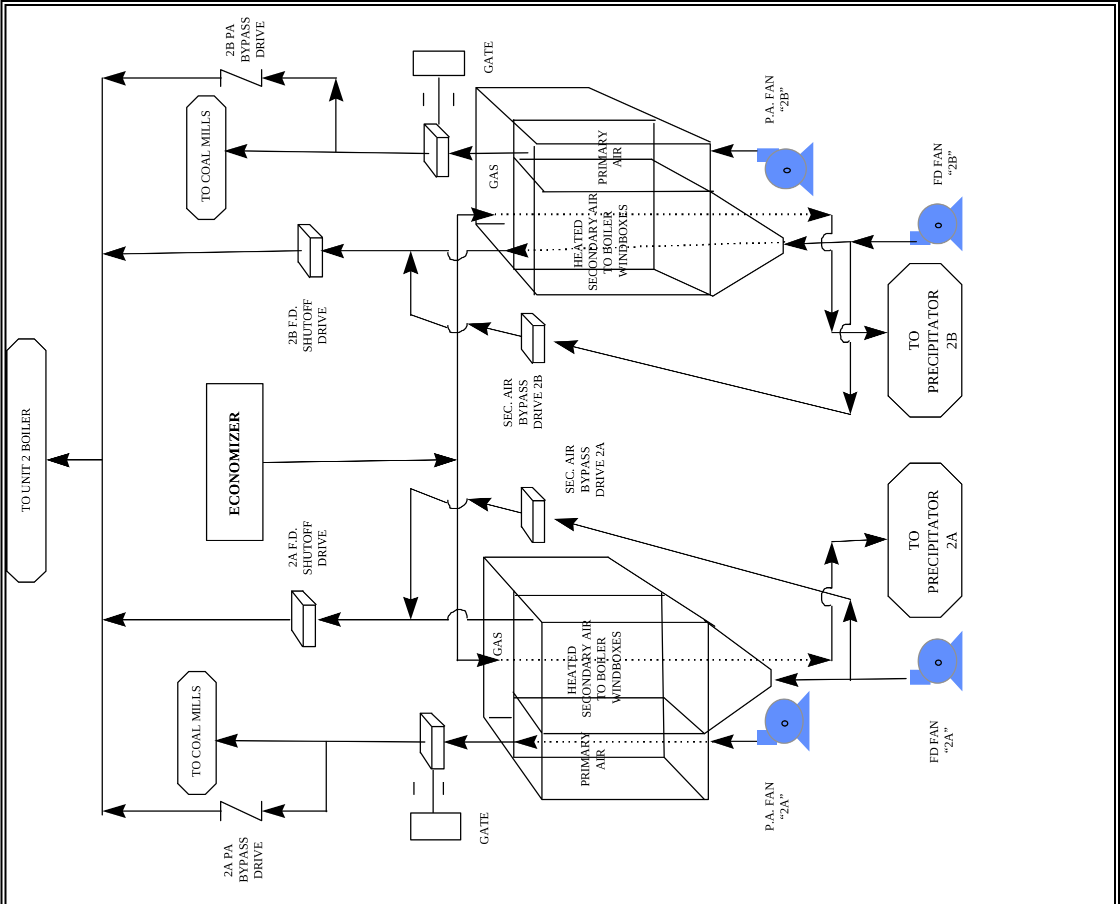


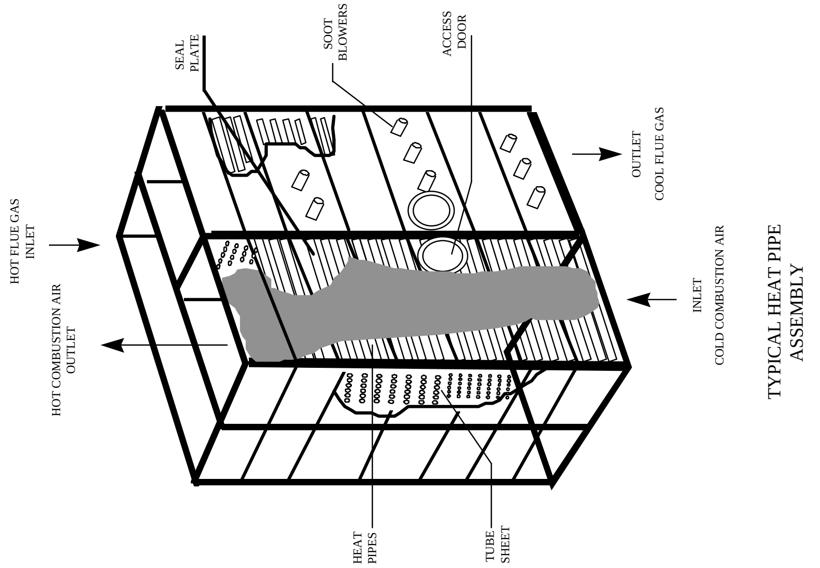
## FIGURE 2.4.-6
## NO$_X$OUT® FLOW DIAGRAM



# FIGURE 2.4-7

# HEAT PIPE AIR HEATER FLOW DIAGRAM





TYPICAL HEAT PIPE ASSEMBLY

## 2.5 STREAM DATA

The purpose of this section is to provide simplified companion tables to the process flow diagrams presented in Section 2.4, Simplified Process Flow Diagrams, giving mass flow rates, compositions, temperatures and pressures for all process streams except for the exclusions noted in Section 2.3, Proprietary Information. The stream data are presented in the following tables.

- Limestone Preparation System Stream Data
  Table 2.5-1

- S-H-U System Stream Data
  Table 2.5-2

- Byproduct Dewatering System Stream Data
  Table 2.5-3

- FGD Wastewater Pretreatment System Stream Data
  Table 2.5-4

- $NO_X$OUT® System Stream Data
  Table 2.5-5

- Heat Pipe Air Heater System Stream Data
  Table 2.5-6

Table is not included for the Brine Concentration System due to proprietary notices from RCC.

# TABLE 2.5-1
# LIMESTONE PREPARATION SYSTEM STREAM DATA

| Stream | Limestone to Ball Mill | Clarified Water to Distribution Box | Clarified Water to Mill Product Tank | Limestone Slurry to Hydrocyclone | Hydrocyclone Underflow | Hydrocyclone Overflow | Limestone to Absorber |
|---|---|---|---|---|---|---|---|
| $CaCO_3$, lb/hr | 45600 | | | 159885 | 114285 | 45600 | 10852 |
| $CaCl_2$, lb/hr | | 1062 | 7432 | 11467 | 2973 | 8494 | 2145 |
| $H_2O$, lb/hr | 2526 | 16973 | 118814 | 186719 | 48407 | 138313 | 34269 |
| HCOOH, lb/hr | | PROP | PROP | PROP | PROP | PROP | PROP |
| Flyash, lb/hr | | 37 | 255 | 394 | 102 | 292 | 73 |
| Inerts, lb/hr | 2400 | | | 8415 | 6015 | 2400 | 571 |
| GPM | | 34 | 236 | 495 | 185 | 308 | 77 |
| Wt % Solids | 95 | 0.2 | 0.2 | 45.9 | 70 | 24.7 | 24.7 |
| Chlorides, ppm | | 40000 | 40000 | 37000 | 37000 | 37000 | 37000 |
| Sp. Gr. | 2.51 | 1.07 | 1.07 | 1.48 | 1.85 | 1.24 | 1.24 |
| Temp, °F | ambient | 115 | 115 | 121 | 121 | 121 | 121 |
| pH | | 4-5 | 4-5 | 6-8 | 6-8 | 6-8 | 6-8 |

# TABLE 2.5-2
# S-H-U SYSTEM STREAM DATA

| Stream | Flue Gas to Absorber | Flue Gas from Absorber | Oxidation Air | Formic Acid to Absorber | Limestone to Absorber | Water to Process | Bleed to Dewatering | Filtrate Return |
|---|---|---|---|---|---|---|---|---|
| $SO_2$, lb/hr | 7068 | 353 | | | | | | |
| HCl, lb/hr | 114 | 6 | | | | | | |
| $MgCO_3$, lb/hr | | | | | | | | |
| $N_2$+$O_2$+$CO_2$, lb/hr | 1538450 | 1560582 | PROP | | | | | |
| $CaCO_3$, lb/hr | | | | | 10852 | | 289 | 72 |
| $CaSO_4•2H_2O$, lb/hr | | | | | | | 24002 | 5955 |
| $CaCl_2$, lb/hr | | | | | 2145 | | 15110 | 12798 |
| $H_2O$, lb/hr | 70873 | 130994 | 154 | 3 | 34269 | 135206 | 241431 | 214080 |
| HCOOH, lb/hr | | | | PROP | PROP | | PROP | PROP |
| Flyash, lb/hr | 141 | 14 | | | 73 | | 515 | 1783 |
| Inerts, lb/hr | | | | | 571 | | 760 | 188 |
| GPM (ACFM) | (487814) | (416140) | PROP | | 77 | 270 | 500 | 432 |
| Wt % Solids | | | | | 25.12 | | 9.57 | 3.21 |
| Chlorides, ppm | | | | | 40000 | | 40000 | 38,500 |
| Sp. Gr. (Density. lb/ft3) | (0.0552) | (0.0678) | | 1.2 | 1.24 | 1.0 | 1.13 | 1.08 |
| Temp, $^oF$ | 270 | 121 | | | 121 | ambient | 121 | 115 |
| Press. In. WG (psig) | 4.7 | 0 | | | | | | |
| pH | | | | | 6-8 | 7 | 4-5 | 4-5 |

# TABLE 2.5-3
# BYPRODUCT DEWATERING SYSTEM STREAM DATA

| Stream | Primary Hydroclone Feed | Wash Water to Centrifuge | Total Filtrate | To Limestone Prep | To Blowdown Treatment | Gypsum Product |
|---|---|---|---|---|---|---|
| $CaCO_3$, lb/hr | 289 | | 143 | | | 434 |
| $CaSO_4 \cdot 2H2O$, lb/hr | 24002 | | 11911 | | | 36093 |
| $CaCl_2$, lb/hr | 15110 | | 25596 | 4290 | 332 | 2 |
| $H_2O$, lb/hr | 241431 | 23366 | 429958 | 68538 | 5311 | 2420 |
| HCOOH, lb/hr | PROP | | PROP | PROP | PROP | |
| Flyash, lb/hr | 515 | | 630 | 146 | 11 | 242 |
| Inerts, lb/hr | 760 | | 377 | | | 1142 |
| GPM | 500 | 47 | 867 | 137 | 11 | |
| Wt % Solids | 9.57 | 0 | 2.95 | .21 | .21 | 94 |
| Chlorides, ppm | 40000 | 0 | 38500 | 40000 | 40000 | 100 |
| Sp. Gr. | 1.13 | 1.0 | 1.08 | 1.07 | 1.07 | 2.31 |
| Temp, $^oF$ | 121 | ambient | 115 | 115 | 115 | 121 |
| pH | 4-5 | 7 | 4-5 | 4-5 | 4-5 | 6-8 |

# TABLE 2.5-4
# FGD WASTEWATER PRETREATMENT SYSTEM STREAM DATA

| Parameter | Influent Stream | Effluent Stream |
|---|---|---|
| Flow Rate, gpm | 11 | 11 |
| Aluminum, mg/liter | 50 - 800 | <1.0 |
| Antimony, mg/liter | NR | <0.04 |
| Arsenic, mg/liter | 0.05 - 3.0 | <0.04 |
| Beryllium, mg/liter | NR | NA |
| Cadmium, mg/liter | 0.04 - 0.5 | <0.05 |
| Chromium, mg/liter | 0.3 - 5.0 | <0.05 |
| Cobalt, mg/liter | 0.05 - 0.4 | <0.10 |
| Copper, mg/liter | 0.1 - 0.85 | <0.23 |
| Iron, mg/liter | 30 - 400 | <0.10 |
| Lead, mg/liter | 0.1 - 3.0 | <0.02 |
| Manganese, mg/liter | NR | <0.10 |
| Mercury, mg/liter | 0.05 - 0.8 | <0.04 |
| Nickel, mg/liter | 0.2 - 6.0 | <0.20 |
| Selenium, mg/liter | 0.2 - 1.0 | <0.06 |
| Silver, mg/liter | NR | <0.12 |
| Tin, mg/liter | NR | <0.3 |
| Vanadium, mg/liter | NR | NA |
| Zinc, mg/liter | 0.4 - 8.0 | <0.10 |
| Magnesium, mg/liter | 8,000 - 12,000 | 208 |
| Calcium, mg/liter | 12,600 - 15,000 | 18100 |
| Chloride, mg/liter | 40,000 - 70,000 | 31310 |
| TSS, mg/liter | 172-513 | <4.0 |
| pH | 3.8 - 4.8 | 10.41 |

Note: The data listed for the influent stream are expected values, not actual measurements. The data listed for the effluent stream are measured values.

## TABLE 2.5-5
## NO$_X$OUT®  SYSTEM STREAM DATA

Stream data from the NOxOUT® demonstration at Seward station were not available at the time of publication. These data will be included in a future topical report.

# TABLE 2.5-6
# HEAT PIPE AIR HEATER STREAM DATA

| Stream | Flue Gas Side (Combined) | Primary Air | Secondary Air |
|---|---|---|---|
| Inlet flow, lb/hr | 750,000 | 62,500 | 562,500 |
| Inlet Temperature, °F | 680 | 80 | 80 |
| Outlet Temperature, °F | 253 | 650 | 617 |
| Specific Heat, Btu/lb-°F | 0.260 | 0.247 | 0.247 |
| Duty, MM Btu/hr | 83.3 | 8.8 | 74.5 |
| Minimum cold Tube Temperature, °F |  | 221 | 170 |
| Guaranteed Pressure Drop, in. WC | 3.65 | 3.60 | 5.35 |

## 2.6 PROCESS AND INSTRUMENT FLOW DIAGRAMS

The process and instrumentation diagrams (P&ID) for the FGD process are included as follows. (P&ID's for the wastewater treatment area are not included due to proprietary notices from IDI and RCC.)

- Limestone Handling
  Figure 2.6-1
- Limestone Preparation
  Figures 2.6-2 through 2.6-7
- S-H-U FGD Process
  Figures 2.6-8 through 2.6-23
- Gypsum Handling
  Figure 2.6-24

## FIGURE 2.6-1
## LIMESTONE HANDLING SYSTEM P&ID

## LEGEND

PREFIX IDENTIFIER / EQUIPMENT NUMBER = DISTRIBUTED CONTROL SYSTEM I/O OR FUNCTION

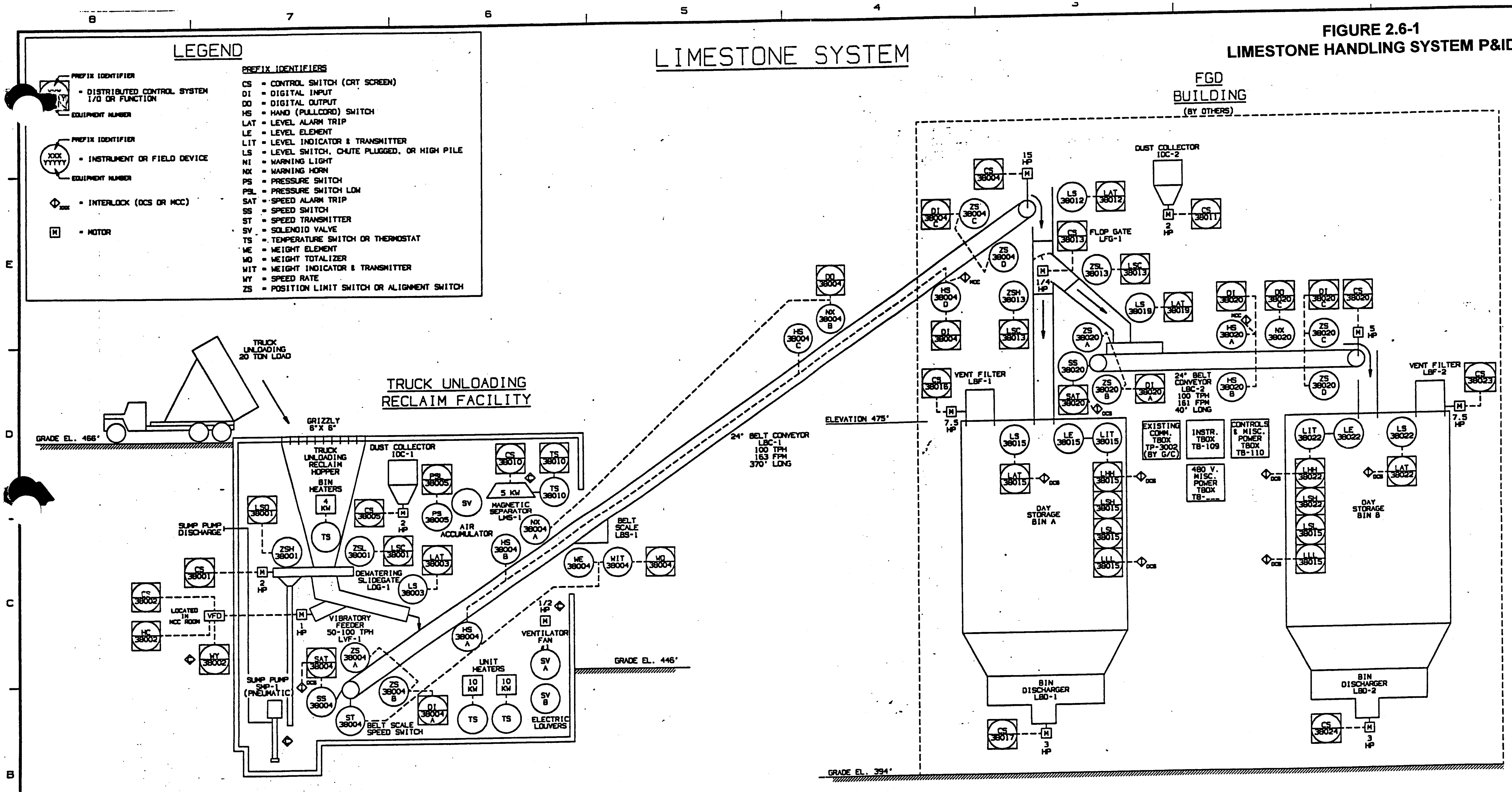
PREFIX IDENTIFIER / EQUIPMENT NUMBER (XXX YYYYY) = INSTRUMENT OR FIELD DEVICE

◇XXX = INTERLOCK (DCS OR MCC)

[M] = MOTOR

PREFIX IDENTIFIERS

- CS = CONTROL SWITCH (CRT SCREEN)
- DI = DIGITAL INPUT
- DO = DIGITAL OUTPUT
- HS = HAND (PULLCORD) SWITCH
- LAT = LEVEL ALARM TRIP
- LE = LEVEL ELEMENT
- LIT = LEVEL INDICATOR & TRANSMITTER
- LS = LEVEL SWITCH, CHUTE PLUGGED, OR HIGH PILE
- NI = WARNING LIGHT
- NX = WARNING HORN
- PS = PRESSURE SWITCH
- PSL = PRESSURE SWITCH LOW
- SAT = SPEED ALARM TRIP
- SS = SPEED SWITCH
- ST = SPEED TRANSMITTER
- SV = SOLENOID VALVE
- TS = TEMPERATURE SWITCH OR THERMOSTAT
- WE = WEIGHT ELEMENT
- WO = WEIGHT TOTALIZER
- WIT = WEIGHT INDICATOR & TRANSMITTER
- WY = SPEED RATE
- ZS = POSITION LIMIT SWITCH OR ALIGNMENT SWITCH



NOTES:

1. ALL MOTORS WILL BE WIRED DIRECTLY TO THE MCC.
2. ALL INSTRUMENT AND FIELD DEVICE DCS SIGNALS WILL BE WIRED TO THE JB-109 BOX LOCATED INSIDE THE FGD BUILDING.
3. PHONES AND OTHER COMMUNICATION EQUIPMENT WILL BE WIRED TO THE EXISTING TP-3002 BOX PROVIDED BY GILBERT/COMMONWEALTH LOCATED INSIDE THE FGD BUILDING.
4. CONTROLS AND MISC. POWER WILL BE WIRED TO THE TB-110 BOX LOCATED INSIDE THE FGD BUILDING.

REFERENCE DRAWINGS

| | |
|---|---|
| JK6191-310 | LOGIC DIAGRAMS-LIMESTONE SYSTEM |
| JK6191-311 | LOGIC DIAGRAMS-LIMESTONE SYSTEM |
| JK6191-315 | LOGIC DIAGRAMS BIN DISCHARGERS |
| JK6191-316 | LOGIC DIAGRAMS-DAY STORAGE BINS "A" & "B" |
| JK6191-317 | LOGIC DIAGRAMS-CONVEYOR LBC-2 |
| JK6191-318 | LOGIC DIAGRAMS-CONVEYOR LBC-1 |
| JK6191-319 | LOGIC DIAGRAMS-VENT FILTERS LBF-1 & LBF-2 |
| JK6191-320 | LOGIC DIAGRAMS-DUST COLLECTORS IDC-1 & IDC-2 |
| JK6191-321 | LOGIC DIAGRAMS-DEWATERING SLIDE GATE LDG-1 |
| JK6191-322 | LOGIC DIAGRAMS-MAGNETIC SEPARATOR LMS-1 |
| JK6191-323 | LOGIC DIAGRAMS-VIBRATORY FEEDER LVF-1 |
| JK6191-324 | LOGIC DIAGRAMS-FLOP GATE LFG-1 |

| REV | DATE | DRAWN | CHECKED | APPROVED | DESCRIPTION OF REVISION |
|---|---|---|---|---|---|
| C | 09-02-93 | Farrell | KAM | JLS | REVISED PER G/C MARK-UPS 8-30-93 |
| B | 07-23-93 | FARRELL | GCI | JLS | REVISED PER G/C MARK-UPS 7-19-93 |
| A | 06-25-93 | FARRELL | JRB | JLS | REVISED PER G/C COMMENTS 6-10-93 |
| 0 | 05-03-93 | FARRELL | SMF | JLS | ORIGINAL |

SCALE NONE

DIMENSION TOLERANCES EXCEPT AS SPECIFIED FRACTIONAL ±1/16" MACHINED FRACTIONAL ±1/32"

LIMESTONE SYSTEM P & I D
LIMESTONE & GYPSUM HANDLING SYS.
NYSEG-MILLIKEN STATION

0 1

DIV EE

FORM REFERENCES

NEW YORK STATE ELECTRIC & GAS CORP.
MILLIKEN STATION
GILBERT/COMMONWEALTH INC.
CONTRACT NO. NSM-F09

GRAPHICS NO.
J_G_6191_EE_0003_C

FMC Corporation
MATERIAL HANDLING SYSTEMS DIV.

JK6191-3

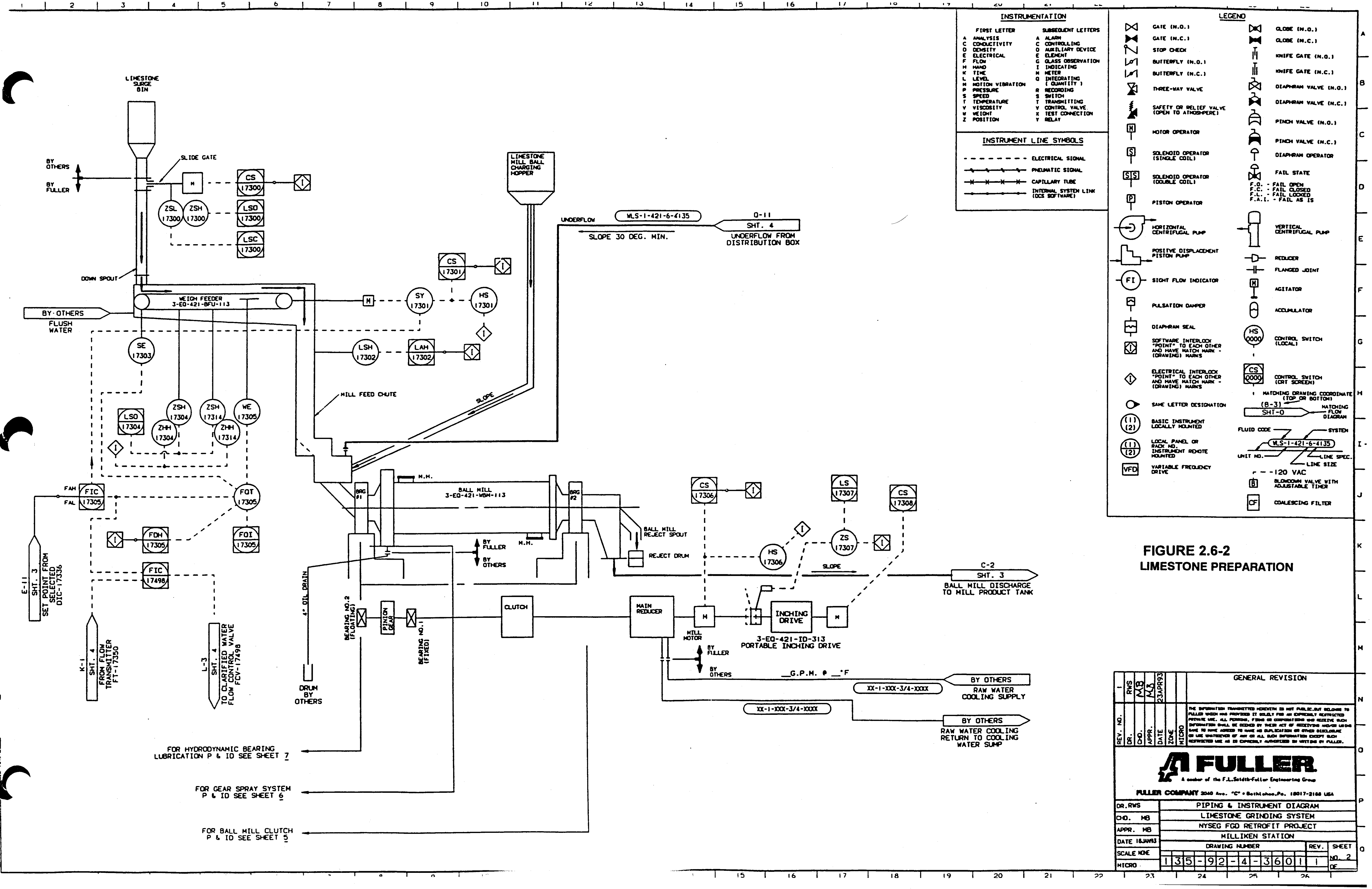


FIGURE 2.6-2
LIMESTONE PREPARATION

| REV. NO. | DR. | CHD. | APPR. | DATE | ZONE | MICRO | |
|---|---|---|---|---|---|---|---|
| 1 | RWS | MB | MB | 23APR93 | | | GENERAL REVISION |

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DR. RWS
CHD. MB
APPR. MB
DATE 18JAN93
SCALE NONE
MICRO

PIPING & INSTRUMENT DIAGRAM
LIMESTONE GRINDING SYSTEM
NYSEG FGD RETROFIT PROJECT
MILLIKEN STATION

DRAWING NUMBER 135-92-4-36011
REV. 1
SHEET NO. 2 OF

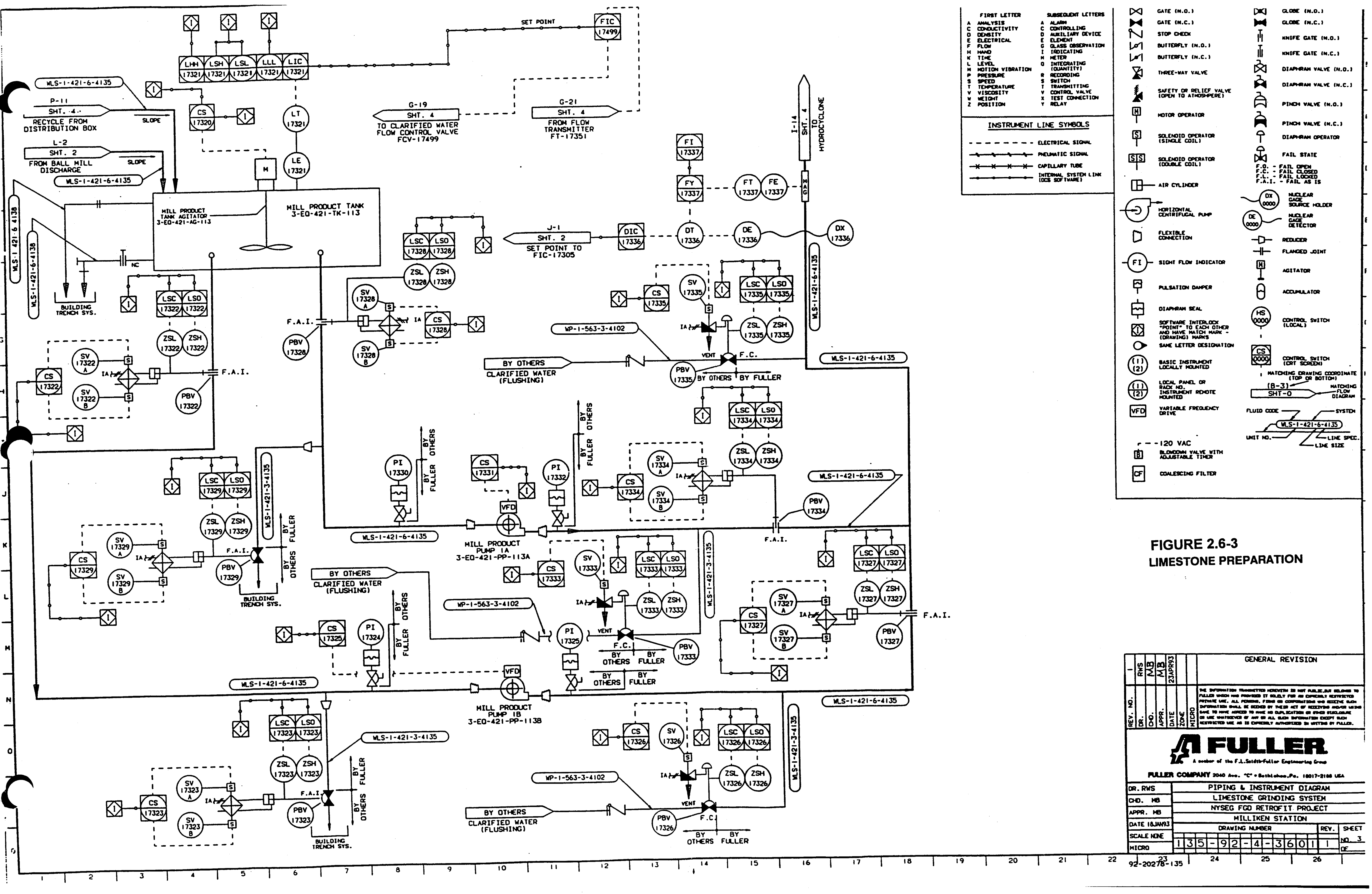

**FIGURE 2.6-3**
**LIMESTONE PREPARATION**

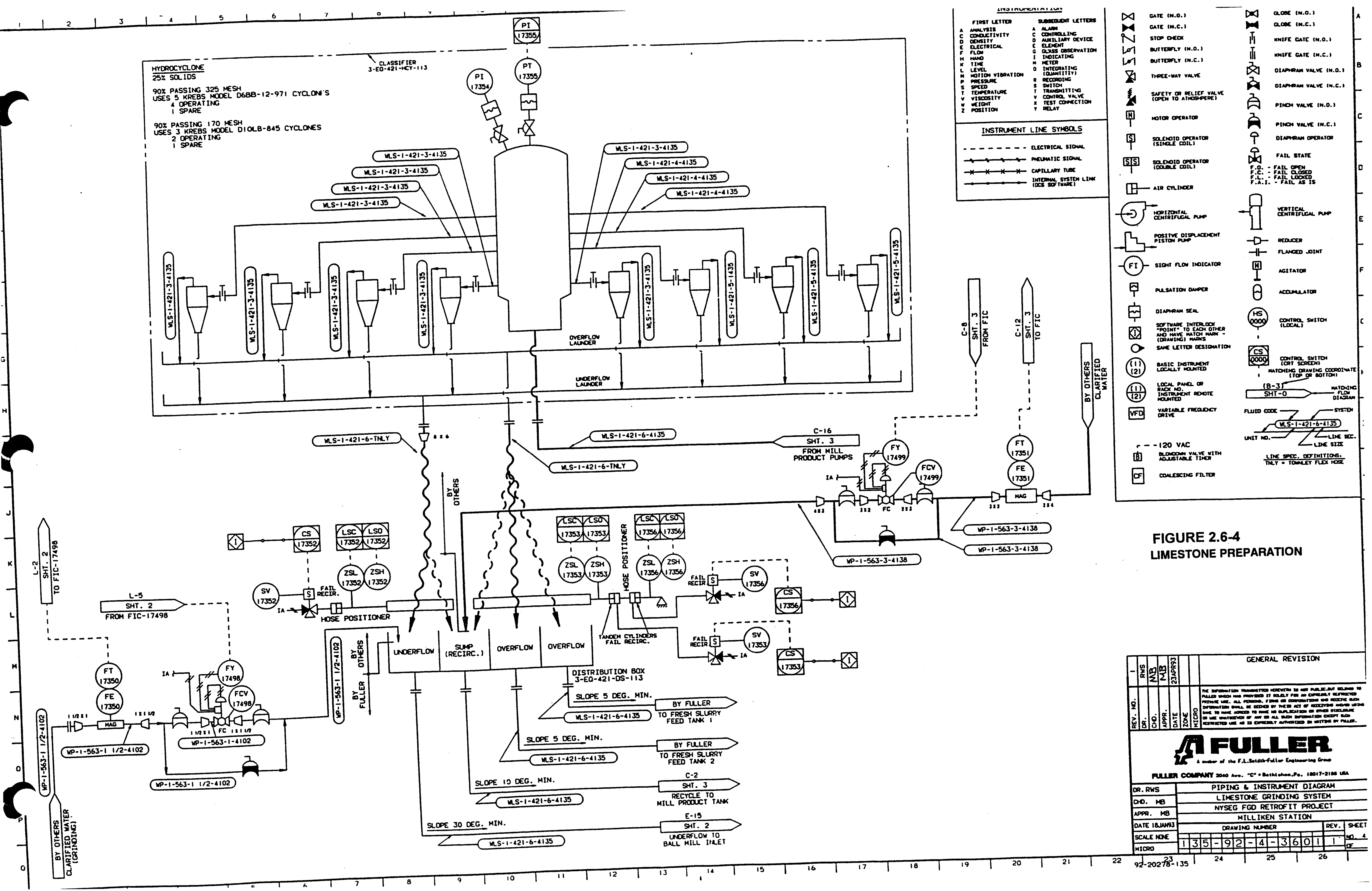

**FIGURE 2.6-4**
**LIMESTONE PREPARATION**

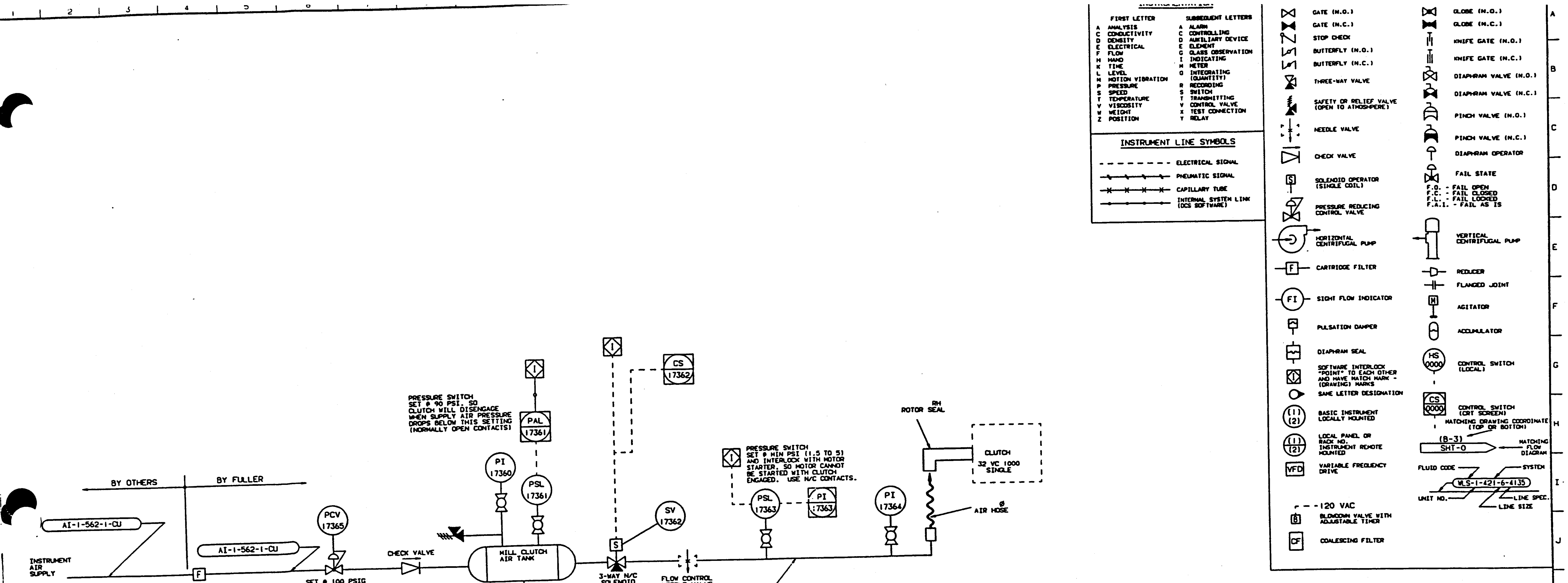

FIGURE 2.6-5
LIMESTONE PREPARATION

| REV. NO. | DR. | CHD. | APPR. | DATE | ZONE | MICRO | |
|---|---|---|---|---|---|---|---|
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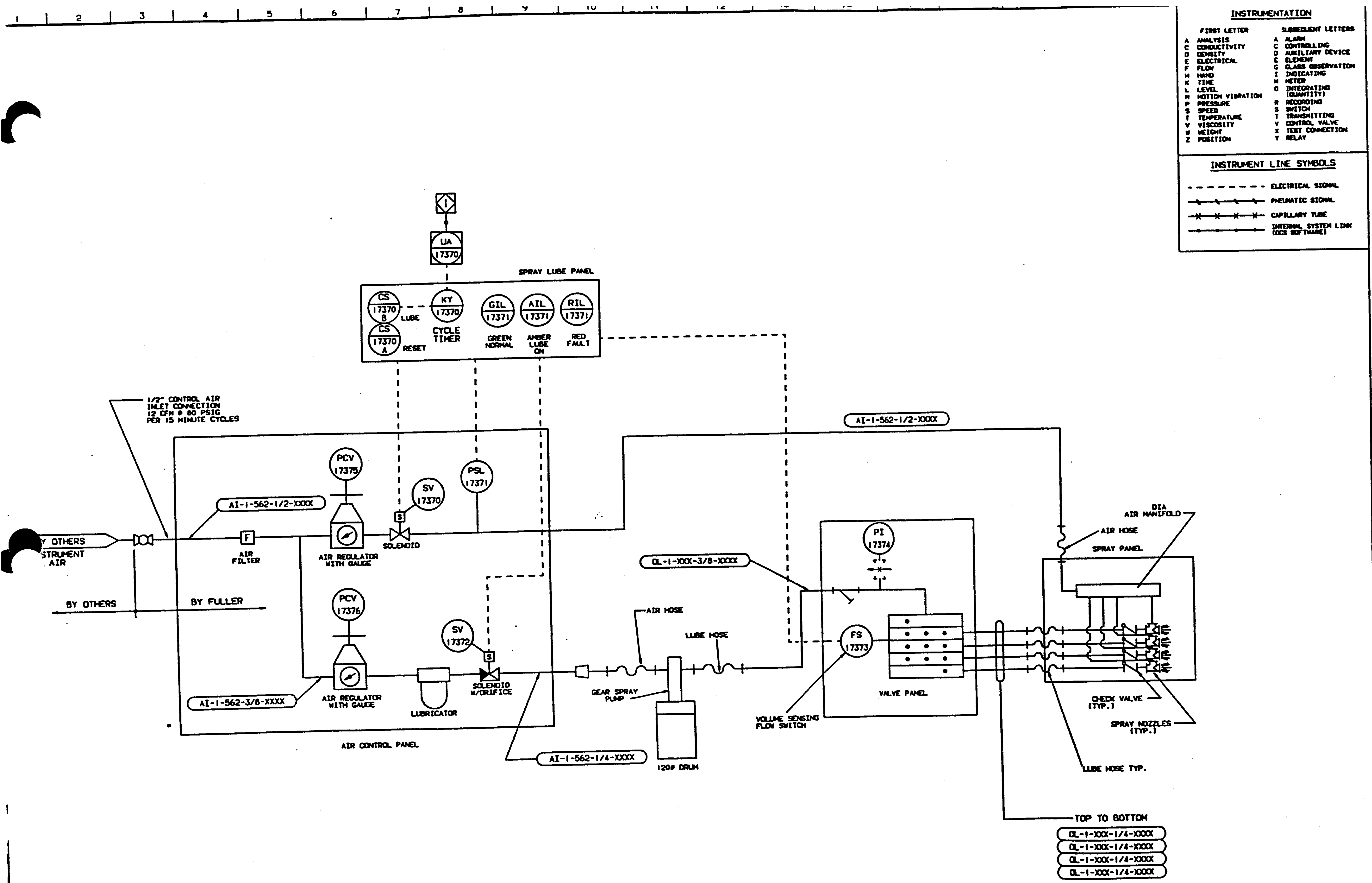
| DR. RWS | PIPING & INSTRUMENT DIAGRAM |
| CHD. MB | LIMESTONE MILL AIR CLUTCH |
| APPR. MB | NYSEG FGD RETROFIT PROJECT |
| DATE 18JAN93 | MILLIKEN STATION |
| SCALE NONE | DRAWING NUMBER 135-92-4-36011 |
| MICRO | REV. 1 |
| | SHEET NO. 5 OF |

92-20278-135



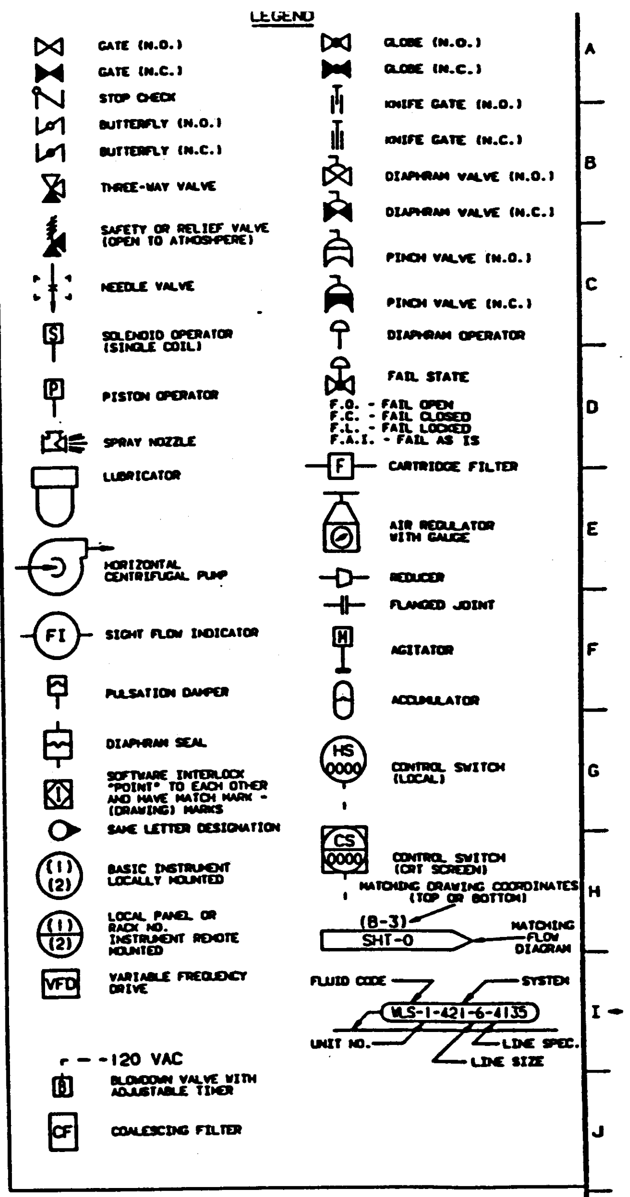


**FIGURE 2.6-6**
**LIMESTONE PREPARATION**

| REV. NO. | DR. | CHD. | APPR. | DATE | ZONE | MICRO | |
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| DR. RWS | PIPING AND INSTUMENT DIAGRAM |
| CHD. MB | LIMESTONE MILL GEAR SPRAY SYSTEM |
| APPR. MB | NYSEG FGD RETROFIT PROJECT |
| DATE 18JAN93 | MILLIKEN STATION |
| SCALE NONE | DRAWING NUMBER: 135-92-4-3601 |
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| | SHEET NO. 6 OF |

22 23 24 25 26

92-20278-135

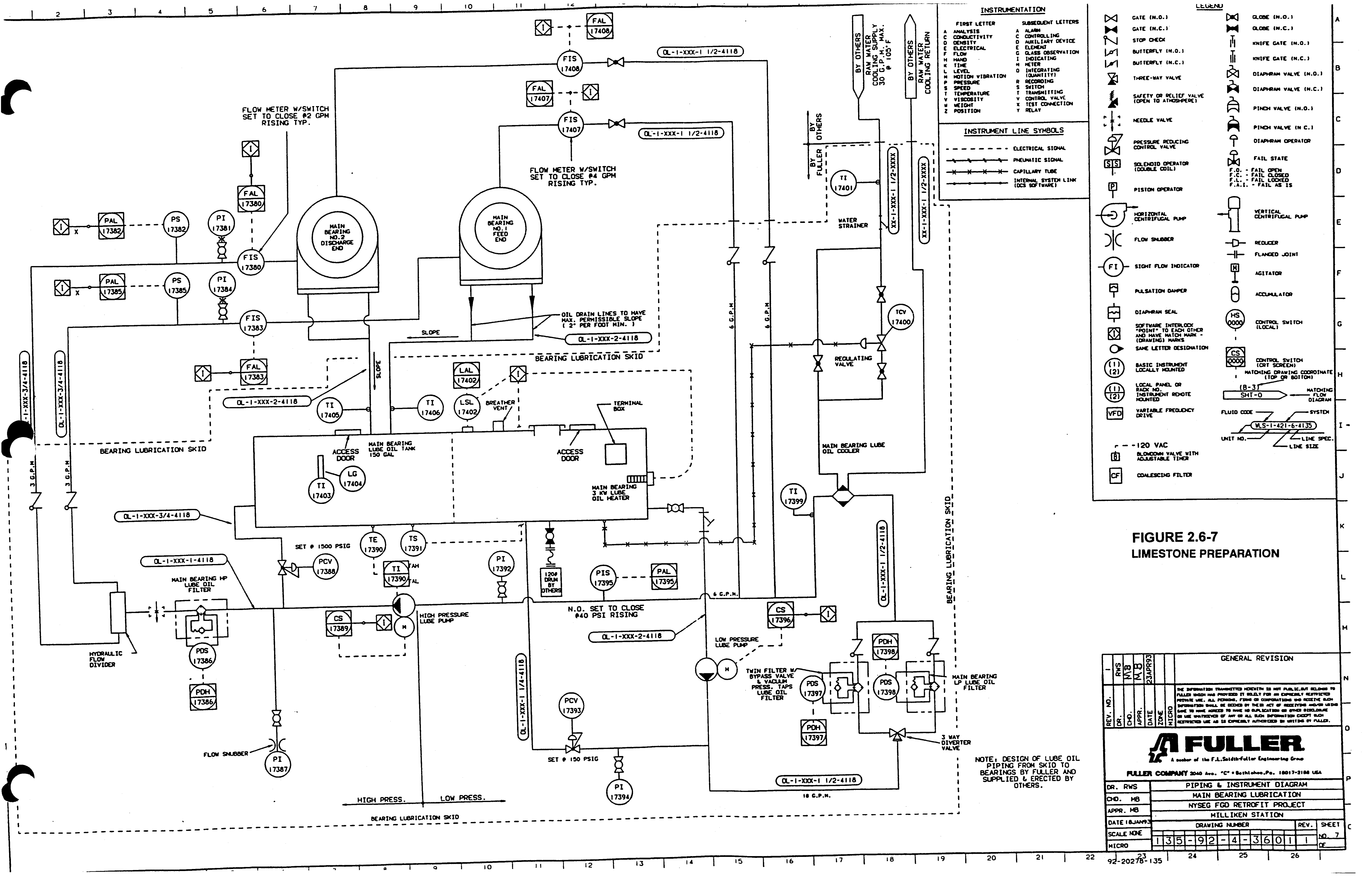
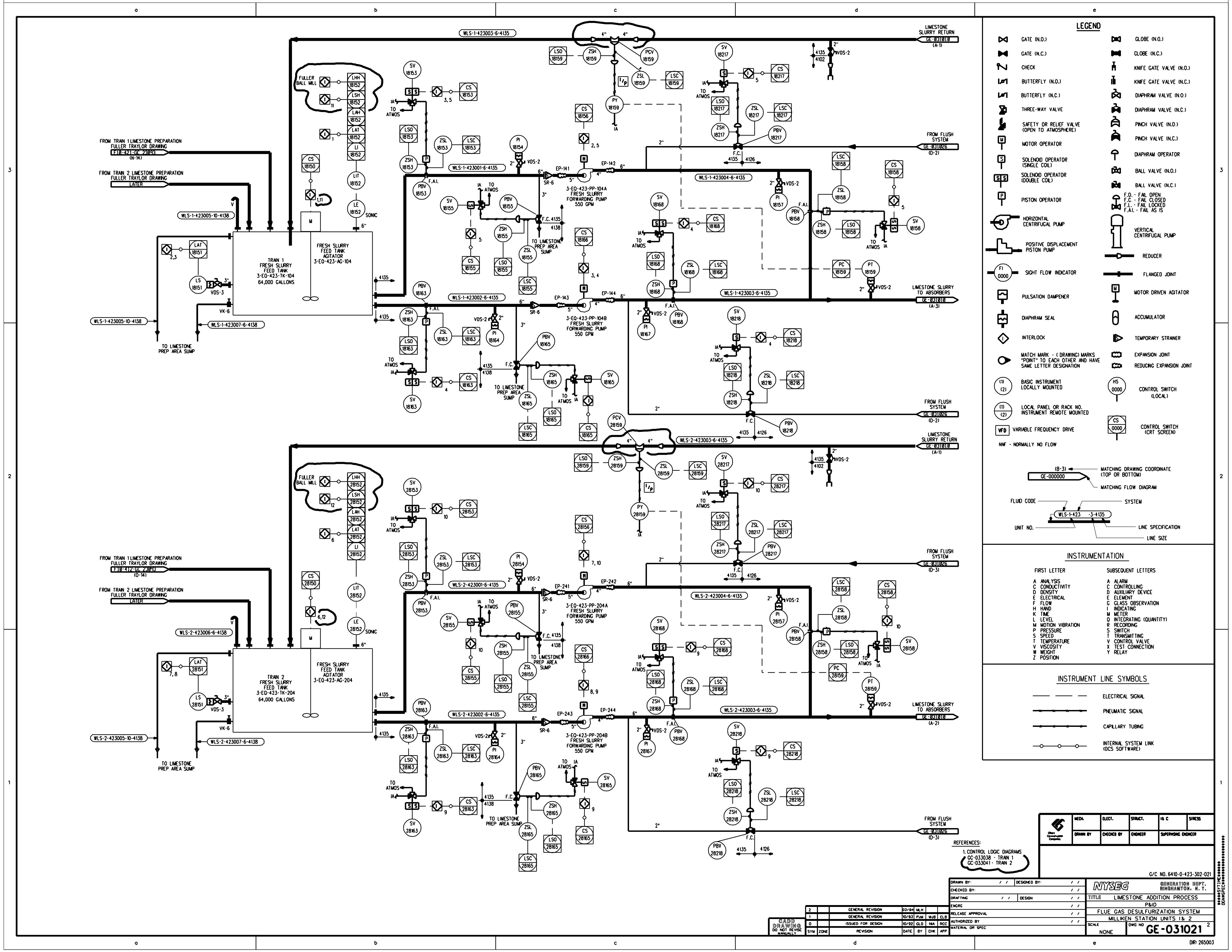


**FIGURE 2.6-7**
**LIMESTONE PREPARATION**



REFERENCES:
1. CONTROL LOGIC DIAGRAMS
GC-033038 - TRAIN 1
GC-033041 - TRAIN 2

G/C NO. 6410-0-423-302-021

| SYM | ZONE | REVISION | DATE | BY | CHK | APP |
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BINGHAMTON, N. Y.

TITLE LIMESTONE ADDITION PROCESS
P&ID
FLUE GAS DESULFURIZATION SYSTEM
MILLIKEN STATION UNITS 1& 2

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DWG NO GE-031021 2

DIR: 265003

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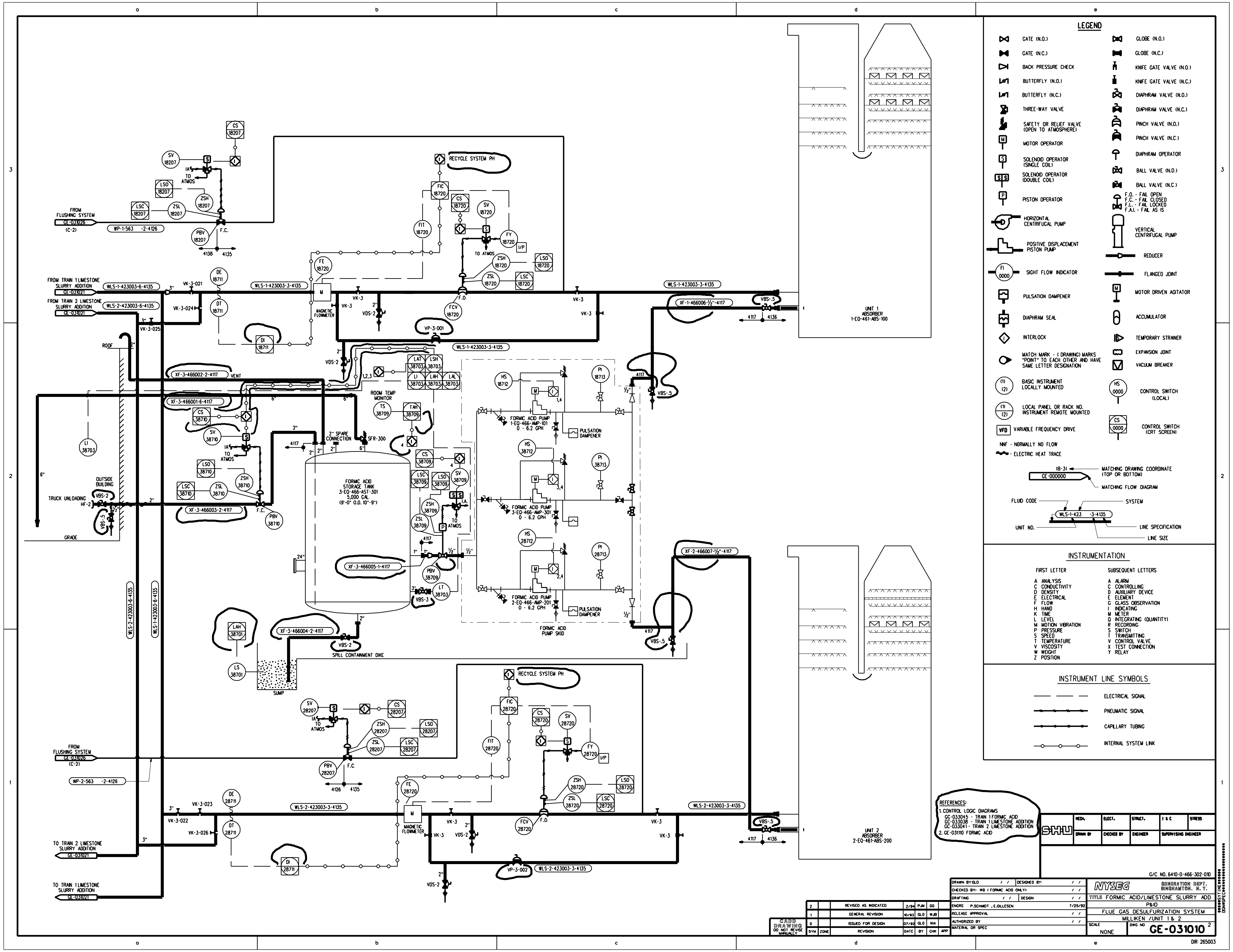

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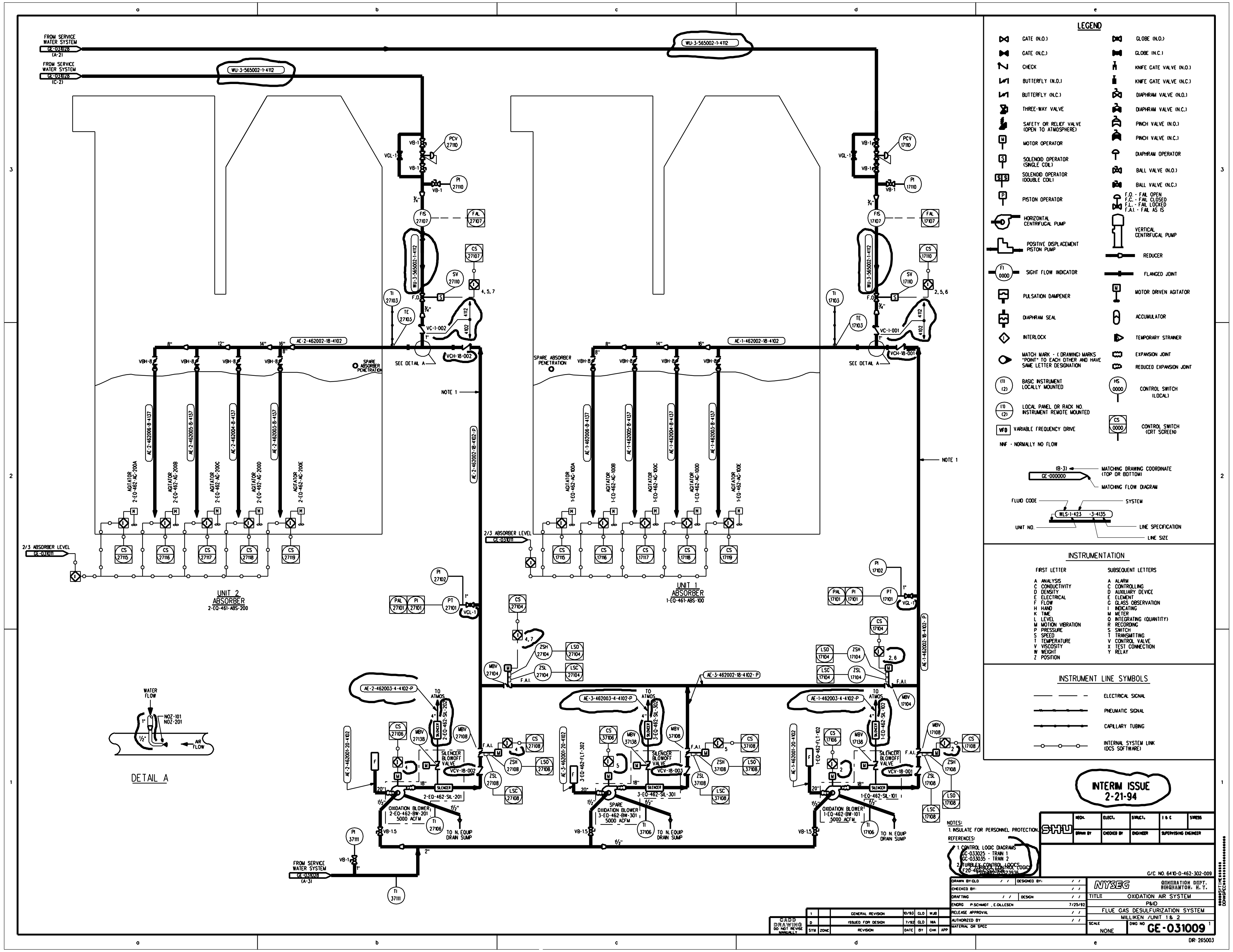

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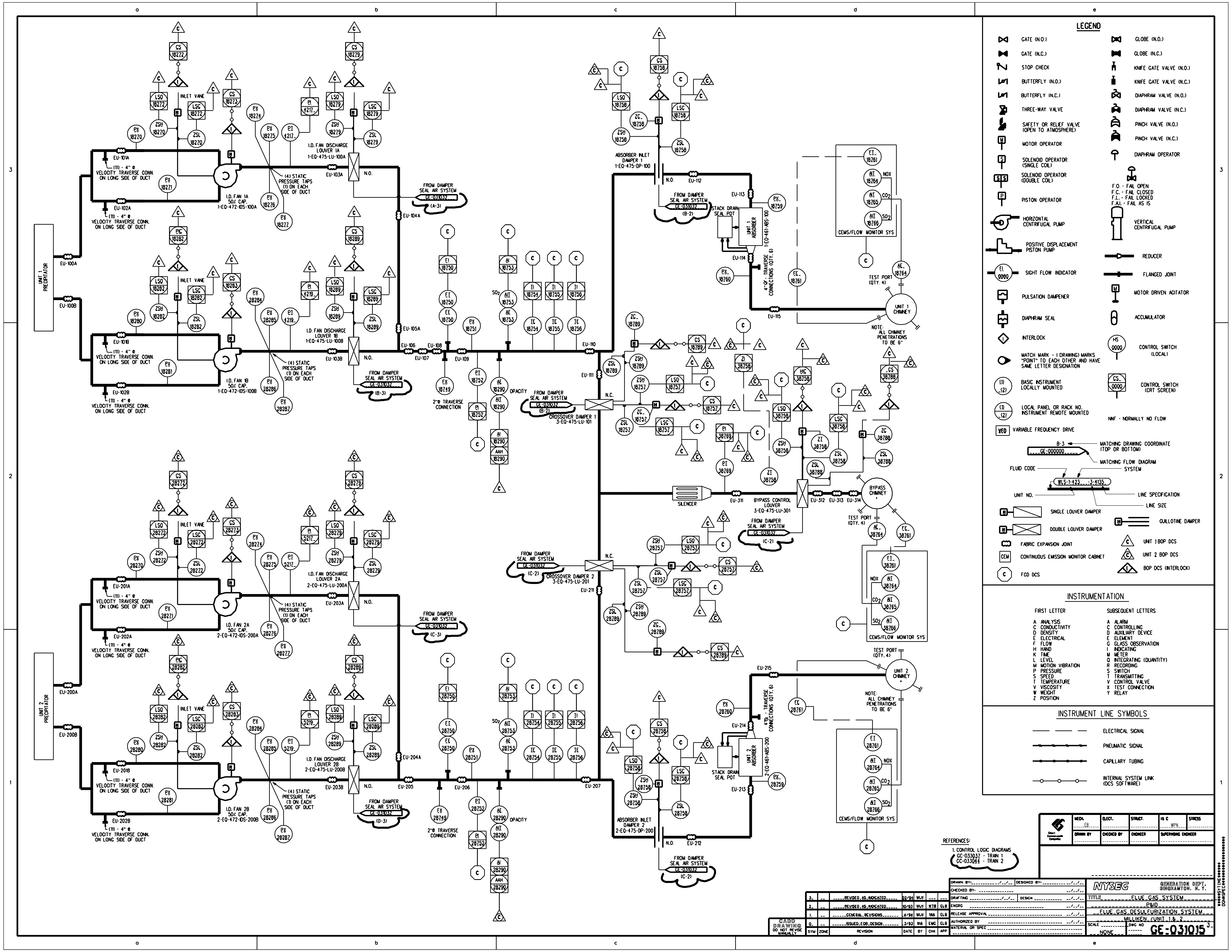

REFERENCES:
1. CONTROL LOGIC DIAGRAMS
GC-033037 - TRAIN 1
GC-033044 - TRAIN 2

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TITLE FLUE GAS SYSTEM
P&ID
FLUE GAS DESULFURIZATION SYSTEM
MILLIKEN /UNIT 1 & 2
SCALE NONE
DWG NO GE-031015 3

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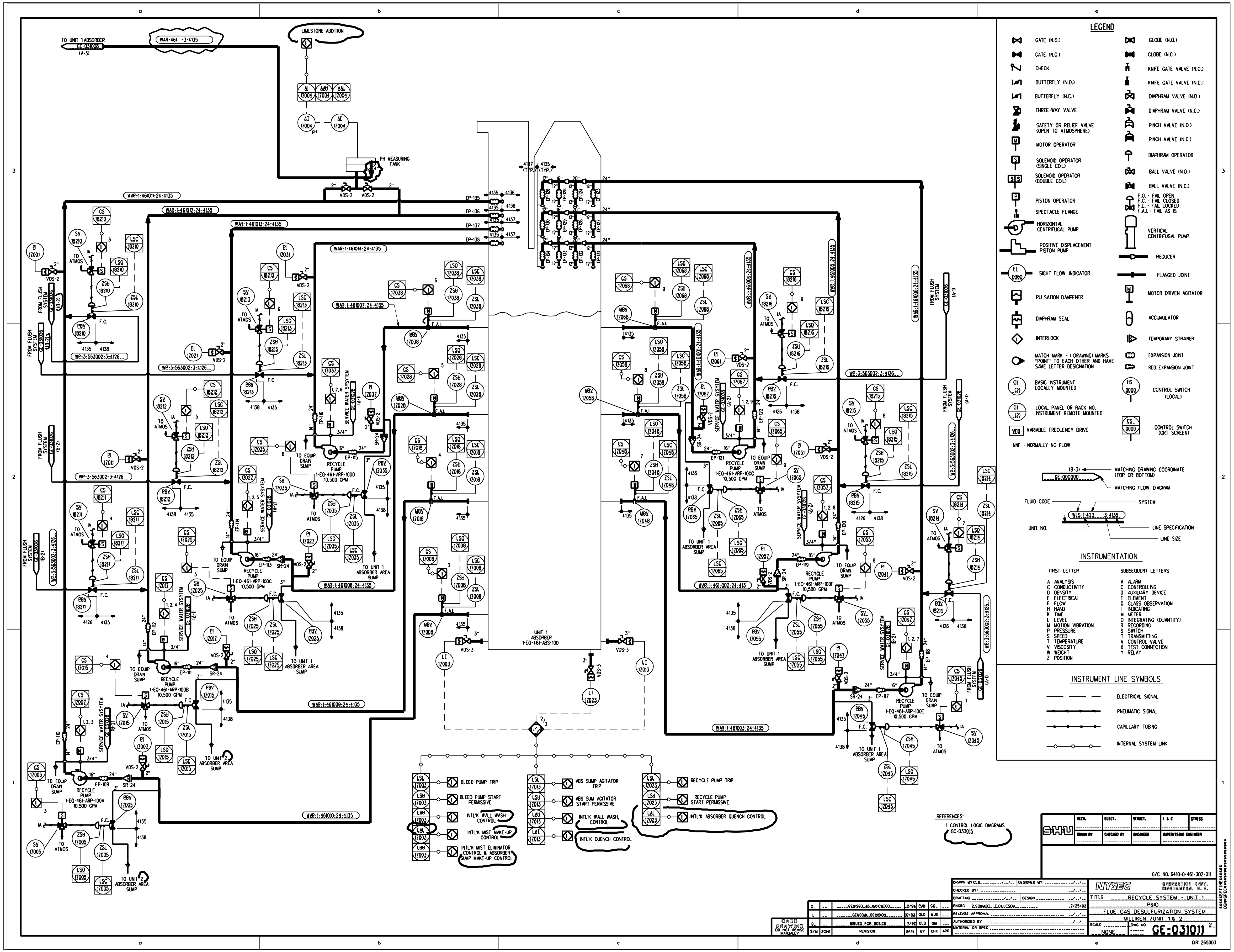

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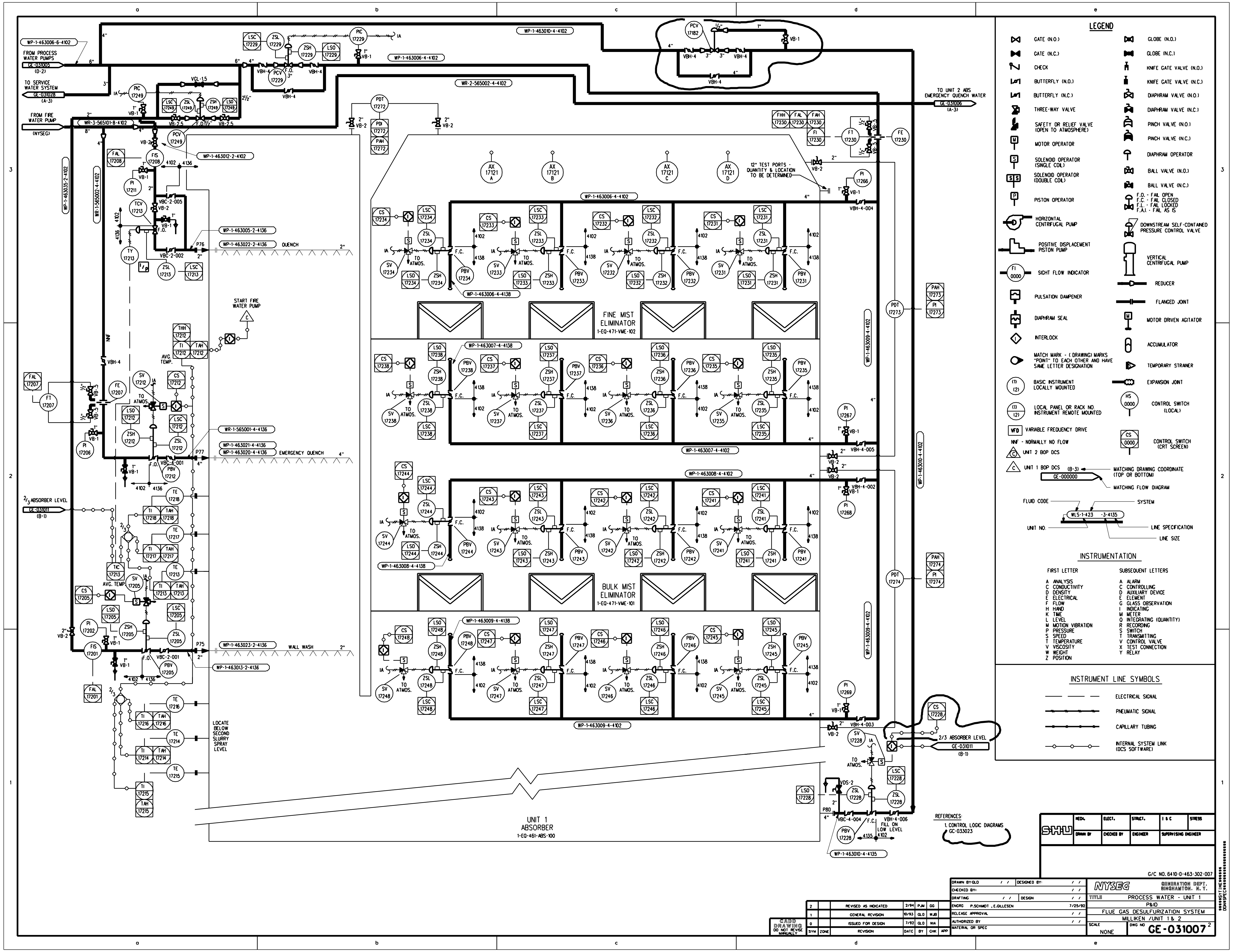

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NYSEG GENERATION DEPT. BINGHAMTON, N. Y.

TITLE PROCESS WATER - UNIT 1
P&ID
FLUE GAS DESULFURIZATION SYSTEM
MILLIKEN /UNIT 1 & 2

SCALE NONE
DWG NO GE-031007 2

$$$$$SYTIME$$$$$$
DGN$SPEC$$$$$$$$$$$$$$$$$$$$

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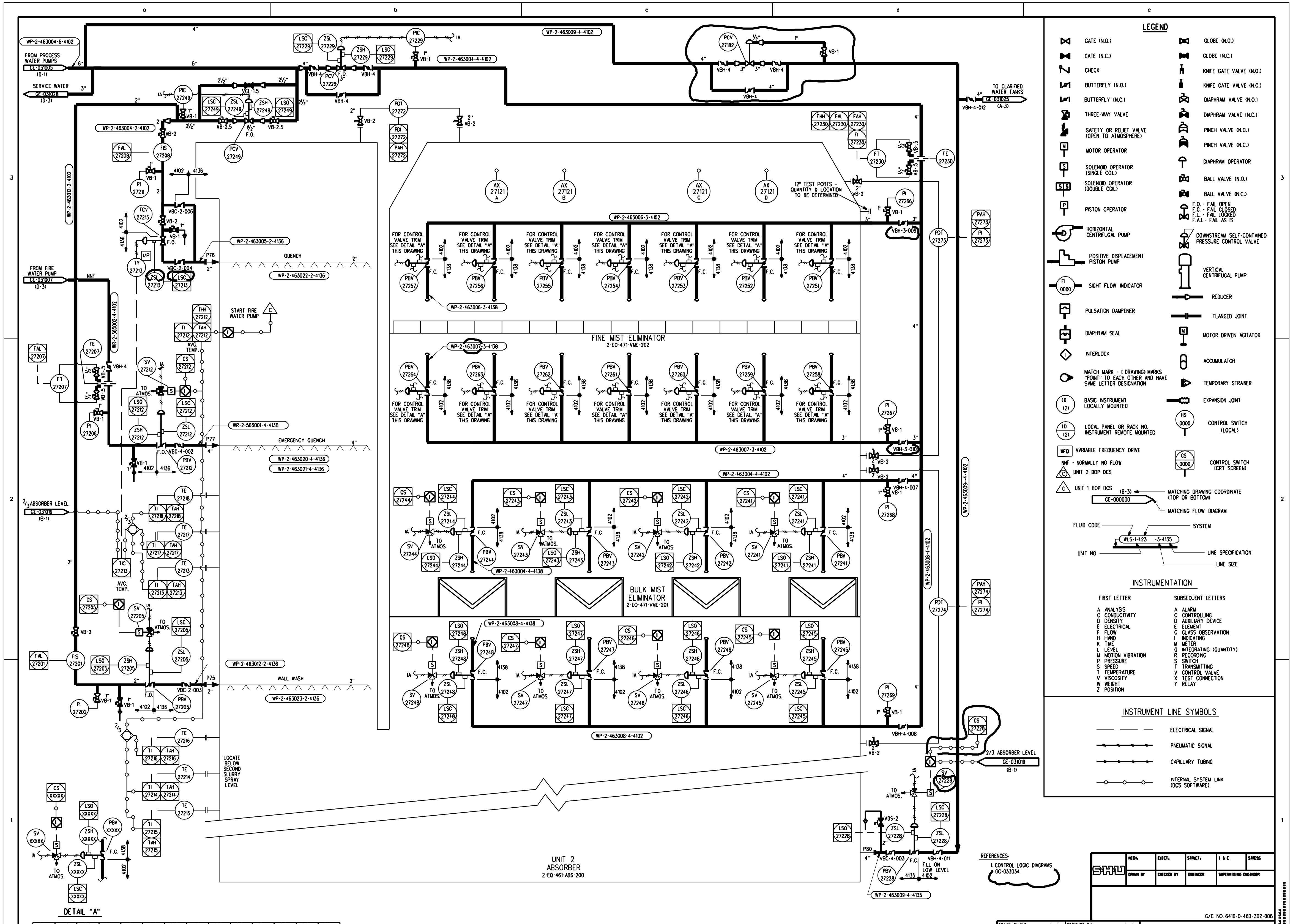

REFERENCES:
1. CONTROL LOGIC DIAGRAMS GC-033034

|  | PBV 27251 | PBV 27252 | PBV 27253 | PBV 27254 | PBV 27255 | PBV 27256 | PBV 27257 | PBV 27258 | PBV 27259 | PBV 27260 | PBV 27261 | PBV 27262 | PBV 27263 | PBV 27264 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ZSL | 27251 | 27252 | 27253 | 27254 | 27255 | 27256 | 27257 | 27258 | 27259 | 27260 | 27261 | 27262 | 27263 | 27264 |
| LSC | 27251 | 27252 | 27253 | 27254 | 27255 | 27256 | 27257 | 27258 | 27259 | 27260 | 27261 | 27262 | 27263 | 27264 |
| ZSH | 27251 | 27252 | 27253 | 27254 | 27255 | 27256 | 27257 | 27258 | 27259 | 27260 | 27261 | 27262 | 27263 | 27264 |
| LSO | 27251 | 27252 | 27253 | 27254 | 27255 | 27256 | 27257 | 27258 | 27259 | 27260 | 27261 | 27262 | 27263 | 27264 |
| CS | 27251 | 27252 | 27253 | 27254 | 27255 | 27256 | 27257 | 27258 | 27259 | 27260 | 27261 | 27262 | 27263 | 27264 |
| SV | 27251 | 27252 | 27253 | 27254 | 27255 | 27256 | 27257 | 27258 | 27259 | 27260 | 27261 | 27262 | 27263 | 27264 |

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S-H-U

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TITLE PROCESS WATER - UNIT 2
P&ID
FLUE GAS DESULFURIZATION SYSTEM
MILLIKEN /UNIT 1 & 2

SCALE NONE
DWG NO GE-031006 2

DIR: 265003

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DGNSSPECSSSSSSSSSSSSSSSSS

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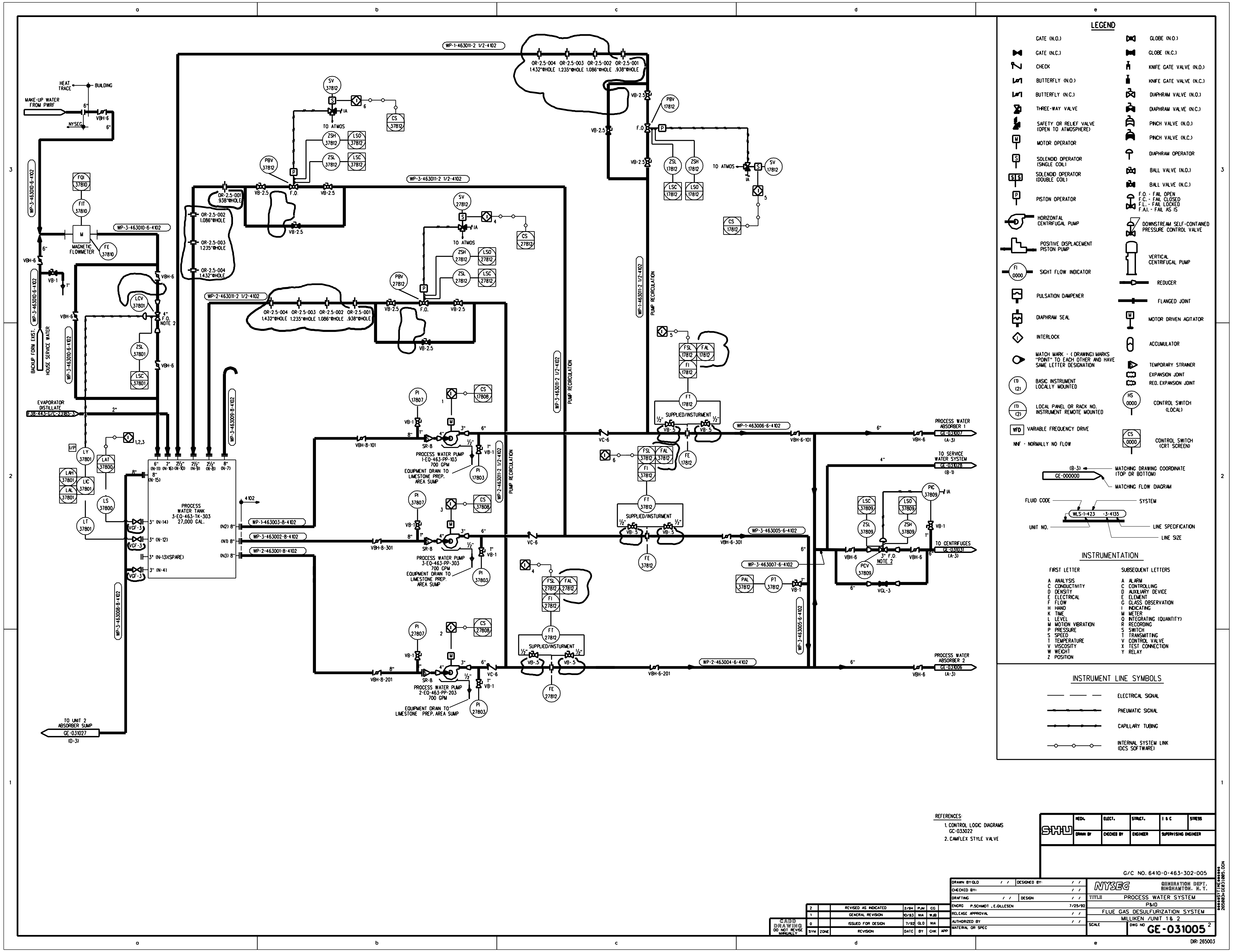

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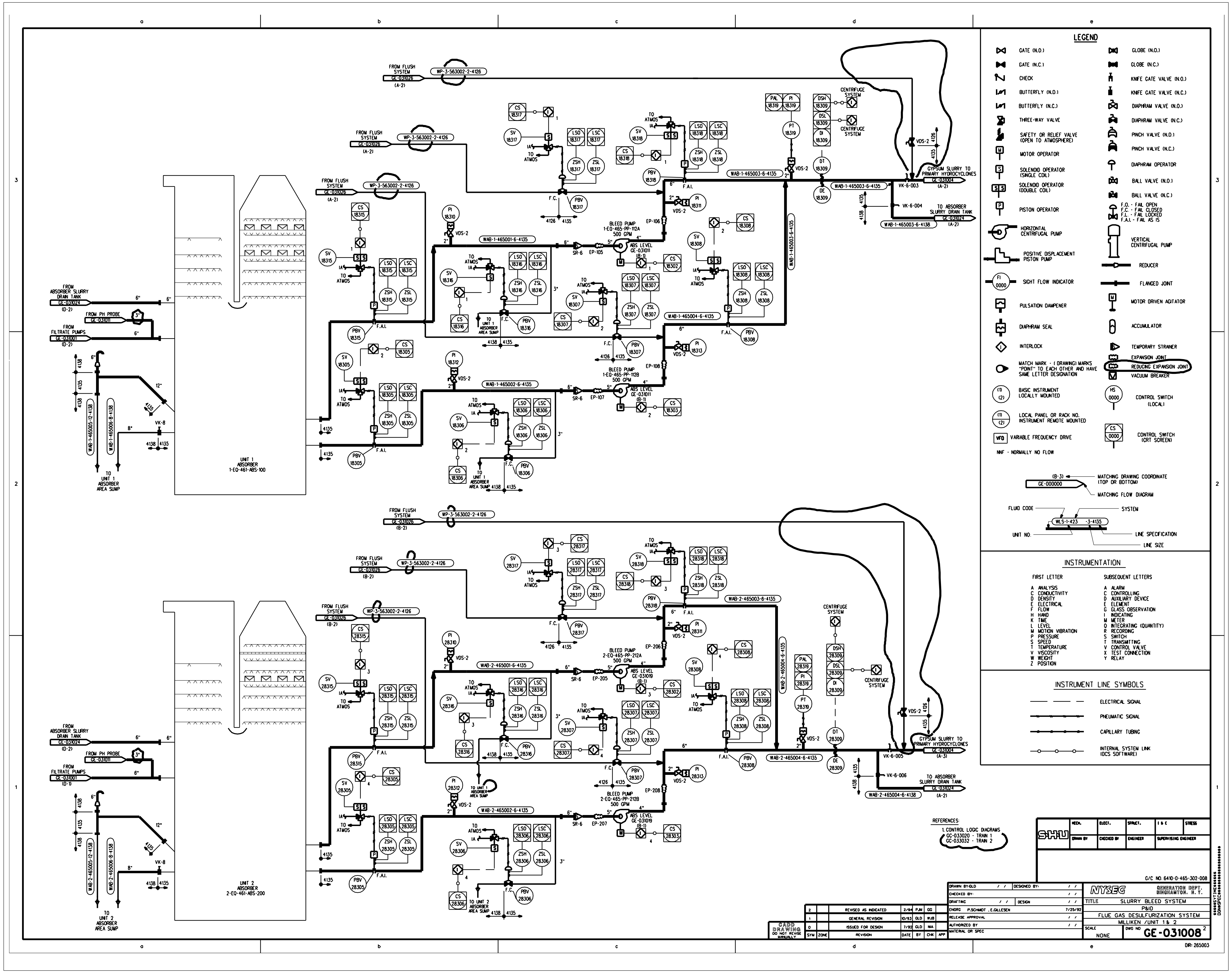

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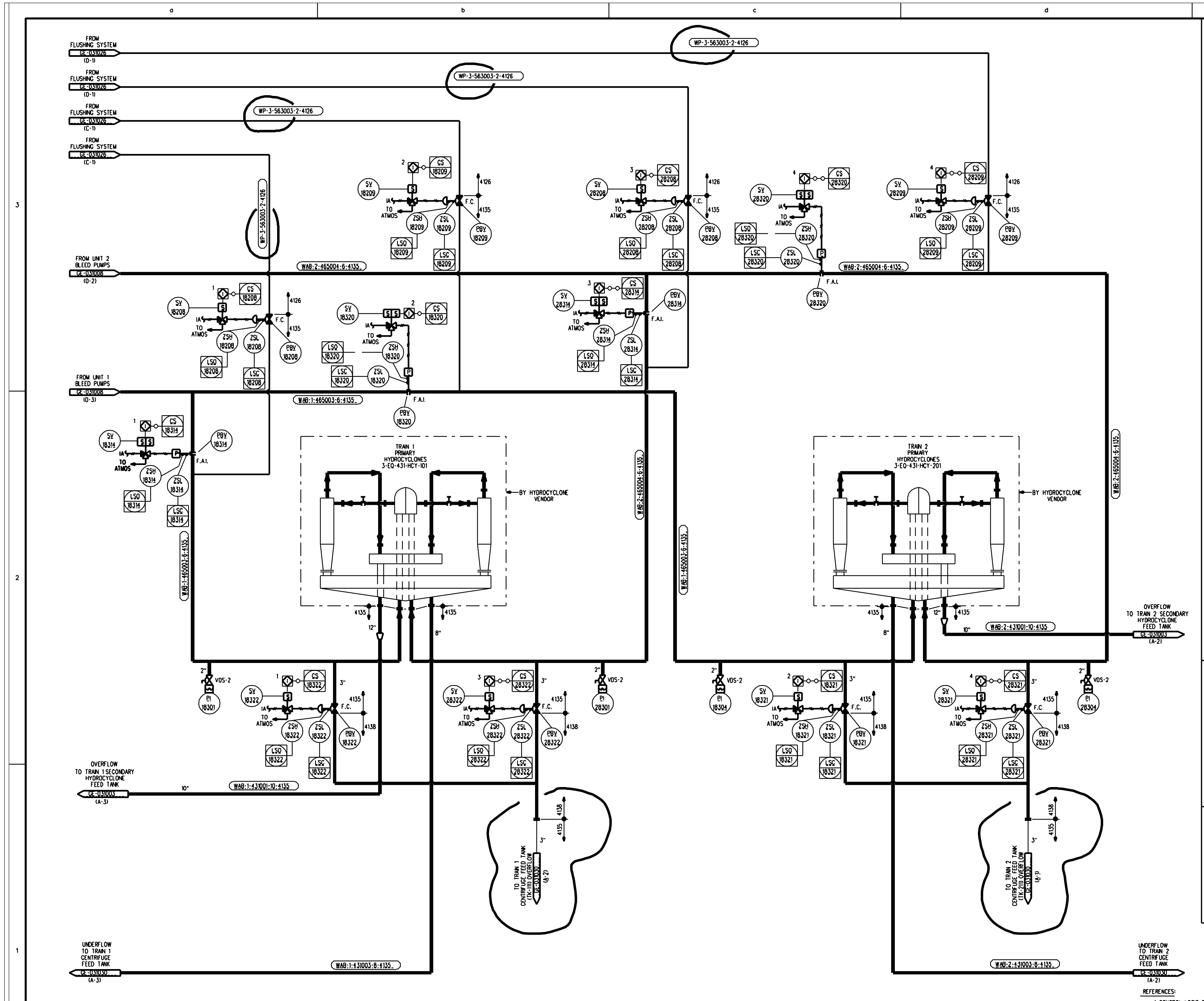

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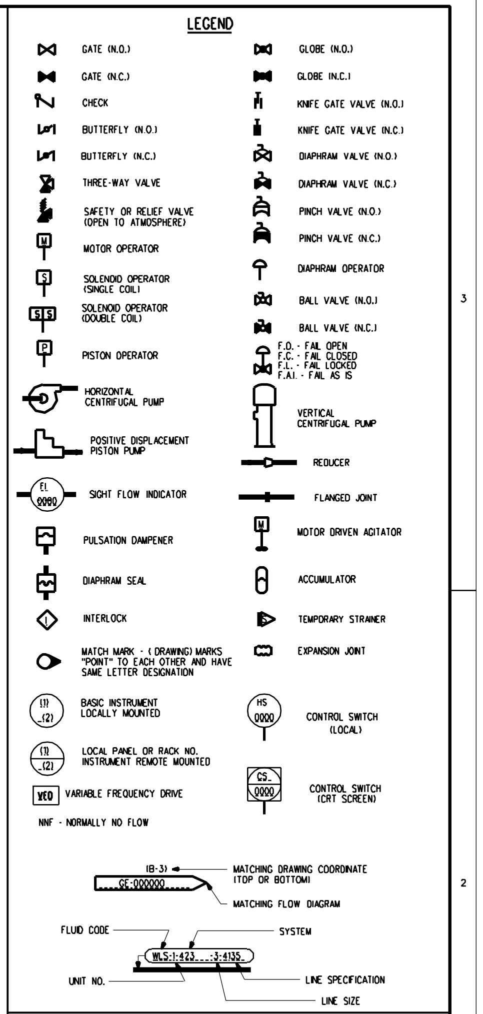
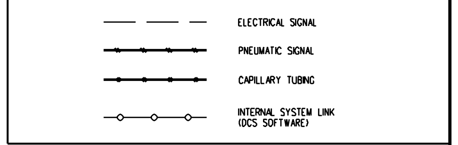


## INSTRUMENTATION

| FIRST LETTER | | SUBSEQUENT LETTERS | |
|---|---|---|---|
| A | ANALYSIS | A | ALARM |
| C | CONDUCTIVITY | C | CONTROLLING |
| D | DENSITY | D | AUXILIARY DEVICE |
| E | ELECTRICAL | E | ELEMENT |
| F | FLOW | G | GLASS OBSERVATION |
| H | HAND | I | INDICATING |
| K | TIME | M | METER |
| L | LEVEL | Q | INTEGRATING (QUANTITY) |
| M | MOTION VIBRATION | R | RECORDING |
| P | PRESSURE | S | SWITCH |
| S | SPEED | T | TRANSMITTING |
| T | TEMPERATURE | V | CONTROL VALVE |
| V | VISCOSITY | X | TEST CONNECTION |
| W | WEIGHT | Y | RELAY |
| Z | POSITION | | |

## INSTRUMENT LINE SYMBOLS



INTERIM ISSUE
2-21-94

REFERENCES:
1. CONTROL LOGIC DIAGRAMS
GC-033019 - TRAIN 1
GC-033031 - TRAIN 2

| S-H-U | MECH. | ELECT. | STRUCT. | I & C | STRESS |
|---|---|---|---|---|---|
| | DRAWN BY | CHECKED BY | ENGINEER | SUPERVISING ENGINEER | |

G/C NO. 6410-0-431-302-004

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| 2 | -- | GENERAL REVISION | 01/94 | MLH | --- | --- |
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GENERATION DEPT.
BINGHAMTON, N.Y.

TITLE PRIMARY DEWATERING
P&ID
FLUE GAS DESULFURIZATION SYSTEM
MILLIKEN /UNITS 1 & 2

SCALE NONE
DWG NO GE-031004 1.

DIR: 265003

$$$$SYTIME$$$$
DGNSPEC$$$$$$$$$$$$$$$$$$

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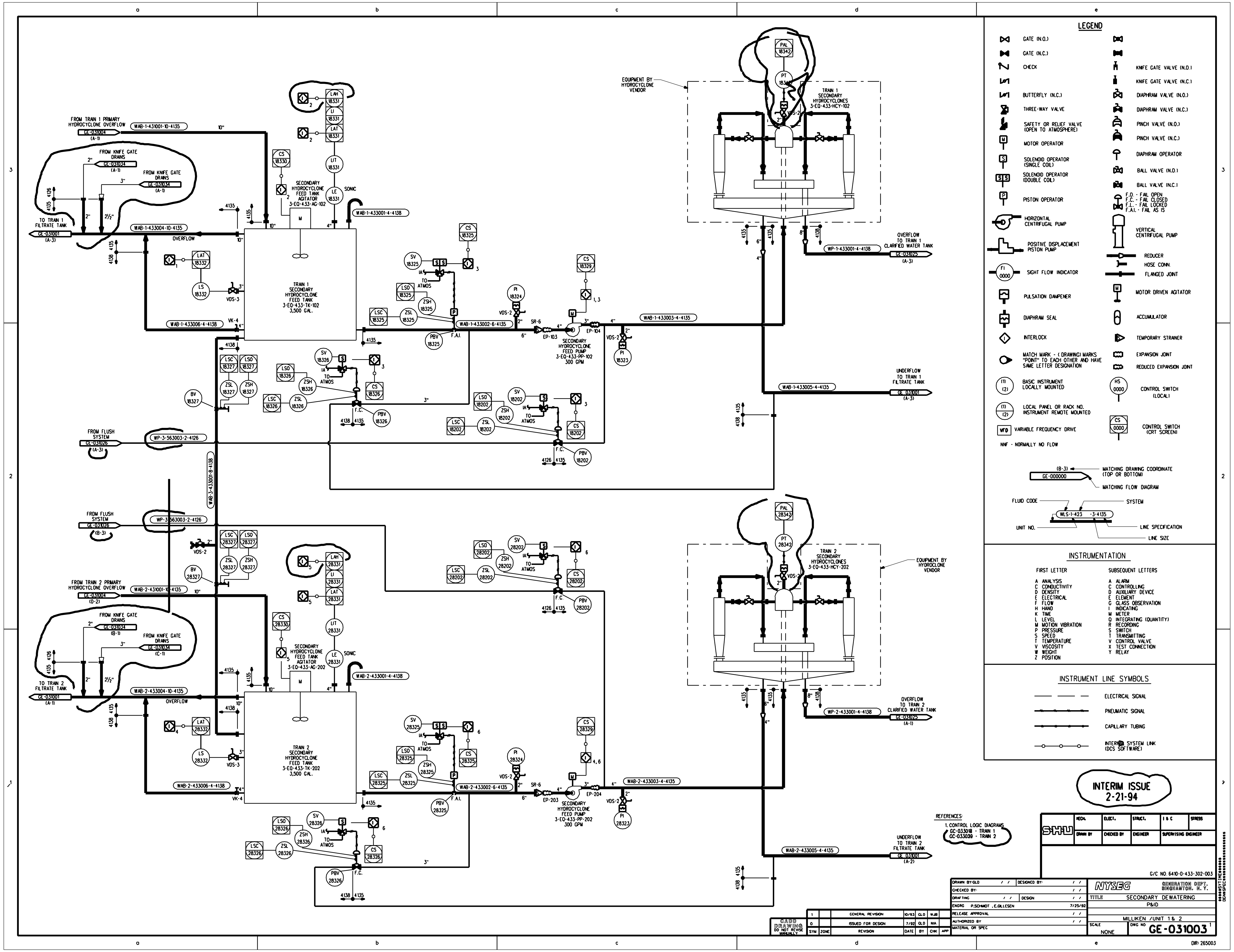

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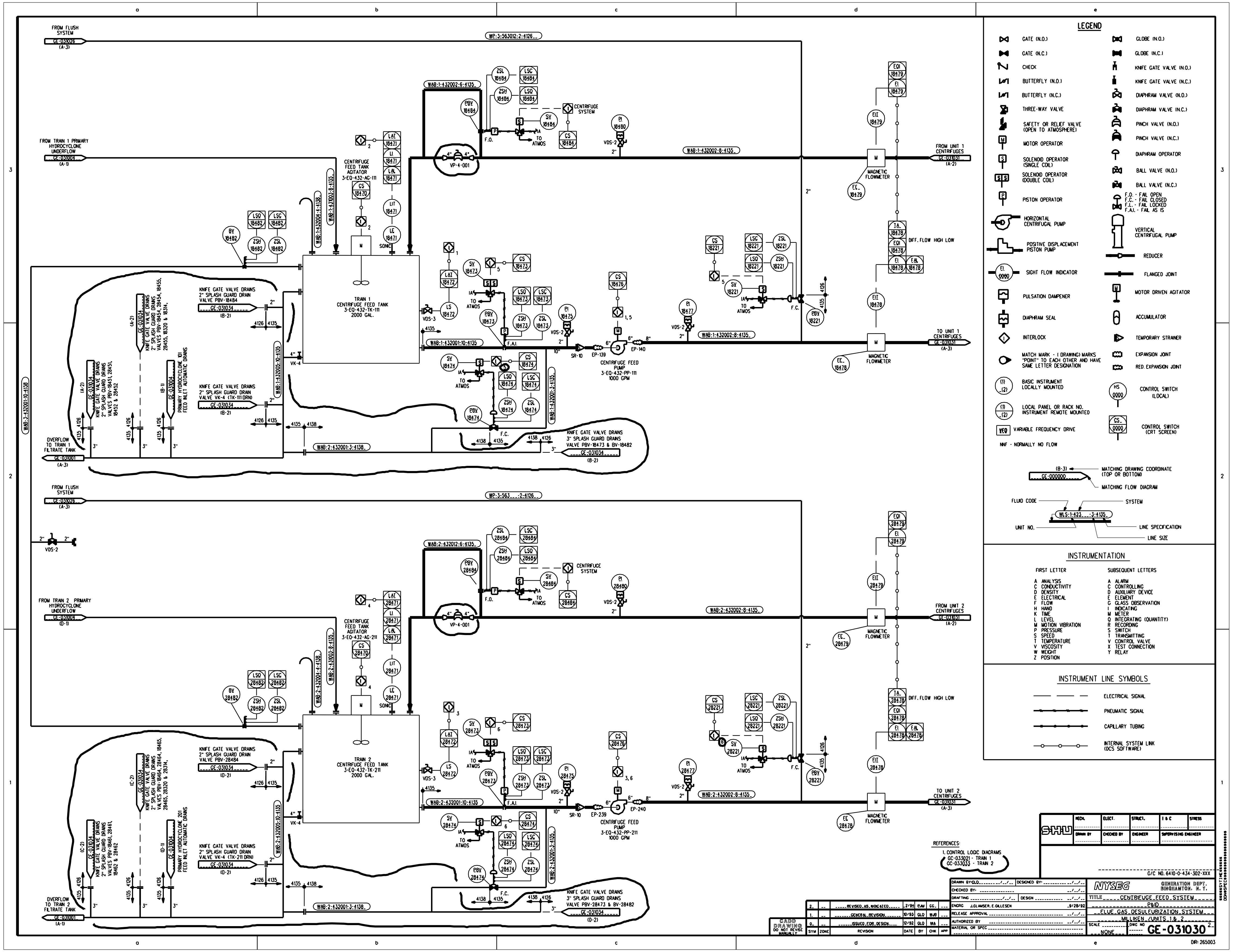

| SYM | ZONE | REVISION | DATE | BY | CHK | APP |
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| 2 | | REVISED AS INDICATED | 2/94 | EJM | GG | |
| 1 | | GENERAL REVISION | 10/93 | GLO | WJB | |
| 0 | | ISSUED FOR DESIGN | 12/92 | GLO | MA | |

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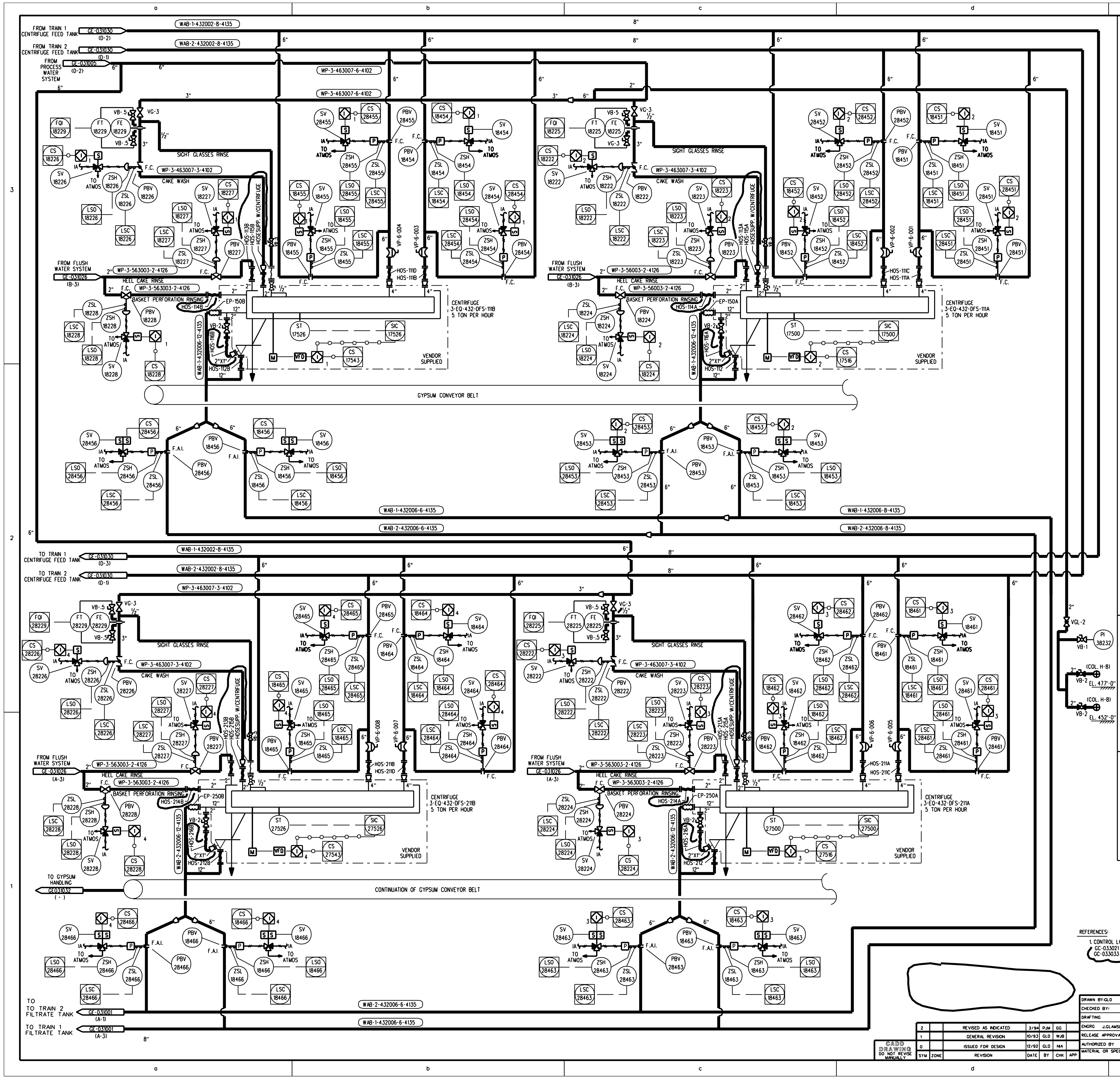
DESIGN ../../..
ENGRG J.GLAMSER, E.GILLESEN 9/28/92
RELEASE APPROVAL ../../..
AUTHORIZED BY ../../..
MATERIAL OR SPEC

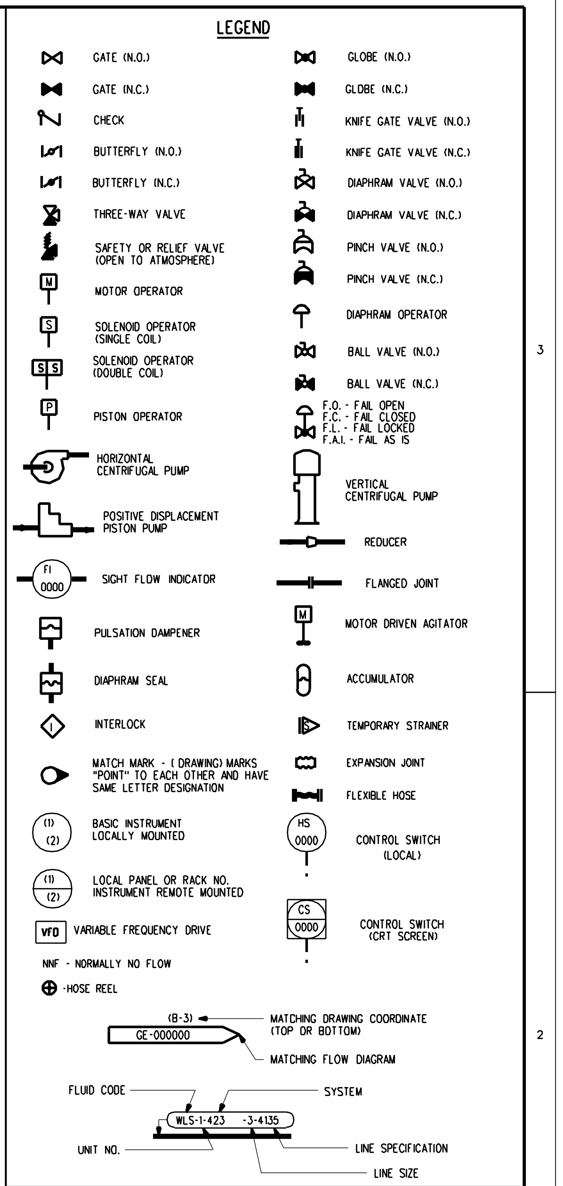
NYSEG GENERATION DEPT. BINGHAMTON, N. Y.

TITLE CENTRIFUGE FEED SYSTEM
P&ID
FLUE GAS DESULFURIZATION SYSTEM
MILLIKEN /UNITS 1 & 2

SCALE NONE
DWG NO GE-031030 2

C:/Session/ge031030.dgn Aug. 06, 1998 15:17:14





## INSTRUMENTATION

| FIRST LETTER | SUBSEQUENT LETTERS |
|---|---|
| A ANALYSIS | A ALARM |
| C CONDUCTIVITY | C CONTROLLING |
| D DENSITY | D AUXILIARY DEVICE |
| E ELECTRICAL | E ELEMENT |
| F FLOW | G GLASS OBSERVATION |
| H HAND | I INDICATING |
| K TIME | M METER |
| L LEVEL | Q INTEGRATING (QUANTITY) |
| M MOTION VIBRATION | R RECORDING |
| P PRESSURE | S SWITCH |
| S SPEED | T TRANSMITTING |
| T TEMPERATURE | V CONTROL VALVE |
| V VISCOSITY | X TEST CONNECTION |
| W WEIGHT | Y RELAY |
| Z POSITION | |

## INSTRUMENT LINE SYMBOLS

| | |
|---|---|
| — — — | ELECTRICAL SIGNAL |
| —✕—✕—✕— | PNEUMATIC SIGNAL |
| —✕—✕—✕— | CAPILLARY TUBING |
| —○—○—○— | INTERNAL SYSTEM LINK (DCS SOFTWARE) |

REFERENCES:
1. CONTROL LOGIC DIAGRAMS
GC-033021 - TRAIN 1
GC-033033 - TRAIN 2

| S-H-U | MECH. | ELECT. | STRUCT. | I & C | STRESS |
|---|---|---|---|---|---|
| | DRAWN BY | CHECKED BY | ENGINEER | SUPERVISING ENGINEER | |

CADD DRAWING
DO NOT REVISE MANUALLY

| SYM | ZONE | REVISION | DATE | BY | CHK | APP |
|---|---|---|---|---|---|---|
| 2 | | REVISED AS INDICATED | 2/94 | PJM | GG | |
| 1 | | GENERAL REVISION | 10/93 | GLD | WJB | |
| 0 | | ISSUED FOR DESIGN | 12/92 | GLD | NIA | |

| | |
|---|---|
| DRAWN BY:GLD / / | DESIGNED BY: / / |
| CHECKED BY: / / | |
| DRAFTING / / | DESIGN / / |
| ENGRG J.GLAMSER, E.GILLESEN 9/28/92 | |
| RELEASE APPROVAL / / | |
| AUTHORIZED BY / / | |
| MATERIAL OR SPEC | |

NYSEG
GENERATION DEPT.
BINGHAMTON, N. Y.

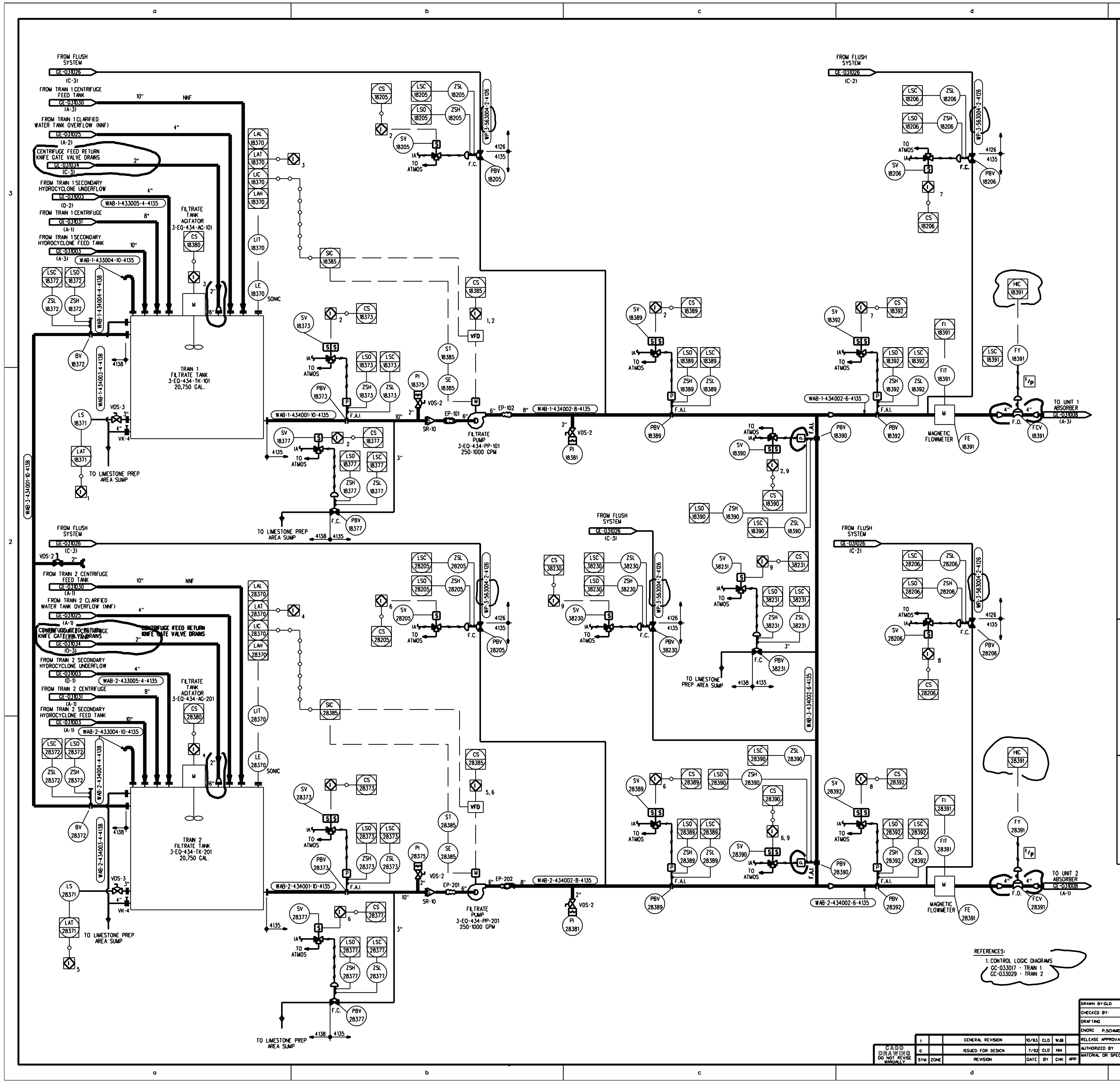
TITLE GYPSUM CENTRIFUGES
P&ID
FLUE GAS DESULFURIZATION SYSTEM
MILLIKEN /UNIT 1 & 2

SCALE NONE
DWG NO GE-031031 2

$$$$$SYTIME$$$$$$
DGN$SPEC$$$$$$$$$$$$$$$$$$$$$

DIR: 265003

C:/Session/GE031031.DGN Jul. 02, 1998 15:46:10



## LEGEND

| | |
|---|---|
| GATE (N.O.) | GLOBE (N.O.) |
| GATE (N.C.) | GLOBE (N.C.) |
| CHECK | KNIFE GATE VALVE (N.O.) |
| BUTTERFLY (N.O.) | KNIFE GATE VALVE (N.C.) |
| BUTTERFLY (N.C.) | DIAPHRAM VALVE (N.O.) |
| THREE-WAY VALVE | DIAPHRAM VALVE (N.C.) |
| SAFETY OR RELIEF VALVE (OPEN TO ATMOSPHERE) | PINCH VALVE (N.O.) |
| MOTOR OPERATOR | PINCH VALVE (N.C.) |
| SOLENOID OPERATOR (SINGLE COIL) | DIAPHRAM OPERATOR |
| SOLENOID OPERATOR (DOUBLE COIL) | BALL VALVE (N.O.) |
| PISTON OPERATOR | BALL VALVE (N.C.) |
| HORIZONTAL CENTRIFUGAL PUMP | F.O. - FAIL OPEN<br>F.C. - FAIL CLOSED<br>F.L. - FAIL LOCKED<br>F.A.I. - FAIL AS IS |
| POSITIVE DISPLACEMENT PISTON PUMP | VERTICAL CENTRIFUGAL PUMP |
| SIGHT FLOW INDICATOR | REDUCER |
| PULSATION DAMPENER | FLANGED JOINT |
| DIAPHRAM SEAL | MOTOR DRIVEN AGITATOR |
| INTERLOCK | ACCUMULATOR |
| MATCH MARK - (DRAWING) MARKS "POINT" TO EACH OTHER AND HAVE SAME LETTER DESIGNATION | TEMPORARY STRAINER |
| BASIC INSTRUMENT LOCALLY MOUNTED | EXPANSION JOINT |
| LOCAL PANEL OR RACK NO. INSTRUMENT REMOTE MOUNTED | REDUCING EXPANSION JOINT |
| VFD VARIABLE FREQUENCY DRIVE | CONTROL SWITCH (LOCAL) |
| NNF - NORMALLY NO FLOW | CONTROL SWITCH (CRT SCREEN) |

(B-3) — MATCHING DRAWING COORDINATE (TOP OR BOTTOM)
GE-000000 — MATCHING FLOW DIAGRAM

WLS-1-423 -3-4135
FLUID CODE
SYSTEM
UNIT NO.
LINE SPECIFICATION
LINE SIZE

## INSTRUMENTATION

| FIRST LETTER | SUBSEQUENT LETTERS |
|---|---|
| A ANALYSIS | A ALARM |
| C CONDUCTIVITY | C CONTROLLING |
| D DENSITY | D AUXILIARY DEVICE |
| E ELECTRICAL | E ELEMENT |
| F FLOW | G GLASS OBSERVATION |
| H HAND | I INDICATING |
| K TIME | M METER |
| L LEVEL | Q INTEGRATING (QUANTITY) |
| M MOTION VIBRATION | R RECORDING |
| P PRESSURE | S SWITCH |
| S SPEED | T TRANSMITTING |
| T TEMPERATURE | V CONTROL VALVE |
| V VISCOSITY | X TEST CONNECTION |
| W WEIGHT | Y RELAY |
| Z POSITION | |

## INSTRUMENT LINE SYMBOLS

ELECTRICAL SIGNAL
PNEUMATIC SIGNAL
CAPILLARY TUBING
INTERNAL SYSTEM LINK (DCS SOFTWARE)

INTERIM ISSUE
2-21-94

REFERENCES:
1. CONTROL LOGIC DIAGRAMS
GC-033017 - TRAIN 1
GC-033029 - TRAIN 2

| | | | | |
|---|---|---|---|---|
| MECH. | ELECT. | STRUCT. | I & C | STRESS |
| DRAWN BY | CHECKED BY | ENGINEER | SUPERVISING ENGINEER | |

S-H-U

G/C NO. 6410-0-434-302-001

| SYM | ZONE | REVISION | DATE | BY | CHK | APP |
|---|---|---|---|---|---|---|
| 1 | | GENERAL REVISION | 10/93 | GLO | WJB | |
| 0 | | ISSUED FOR DESIGN | 7/92 | GLO | NIA | |

CADD DRAWING DO NOT REVISE MANUALLY

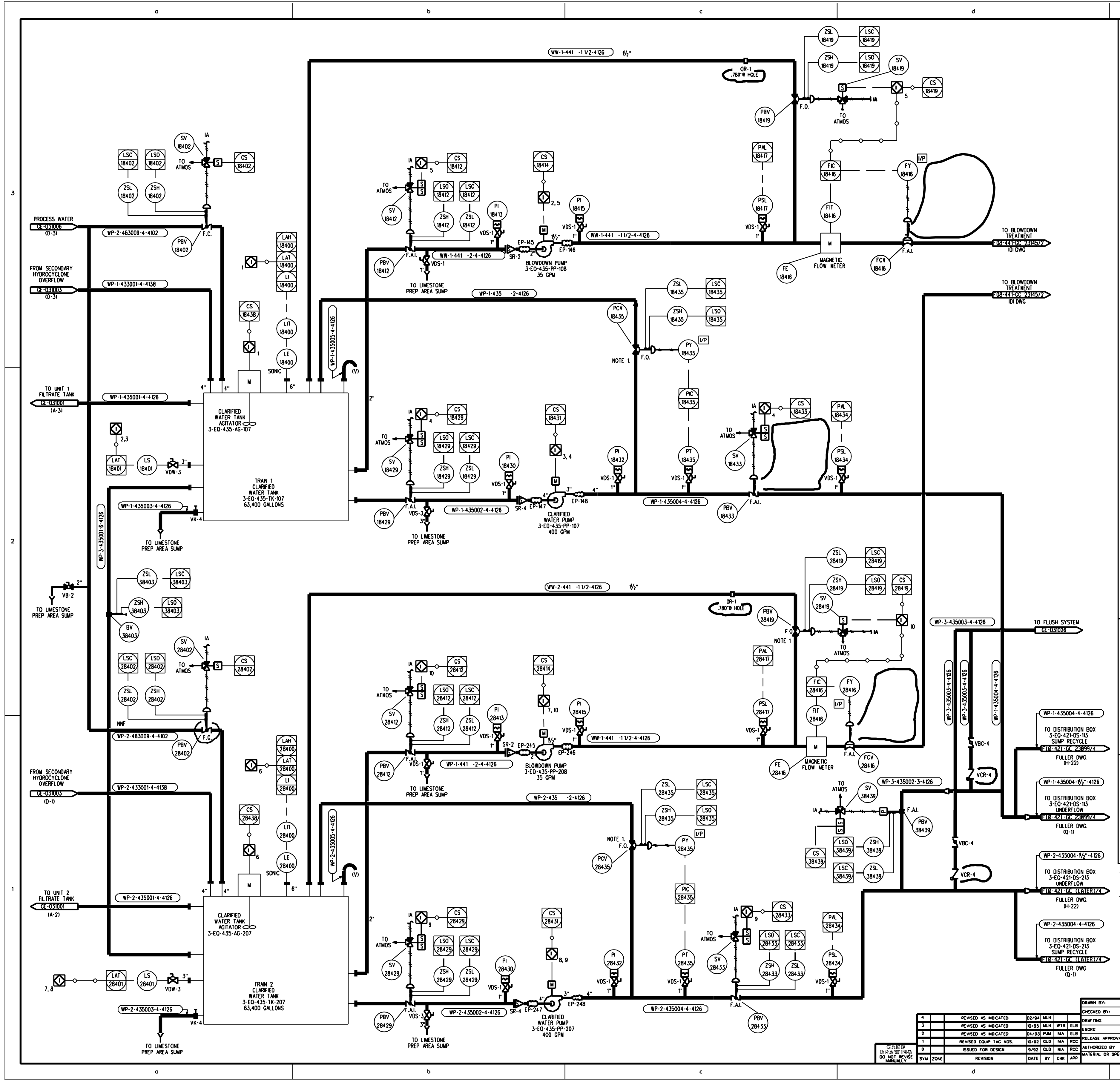
DRAWN BY:GLO / /
DESIGNED BY: / /
CHECKED BY: / /
DRAFTING / /
DESIGN / /
ENGRG P.SCHMIDT , E.GILLESEN 7/25/92
RELEASE APPROVAL / /
AUTHORIZED BY / /
MATERIAL OR SPEC

NYSEG
GENERATION DEPT.
BINGHAMTON, N. Y.
TITLE FILTRATE SYSTEM
P&ID
FLUE GAS DESULFURIZATION SYSTEM
MILLIKEN /UNITS 1& 2
SCALE NONE
DWG NO GE-031001 1

DIR: 265003

$$$$$SYTIME$$$$$
DGN$SPEC$$$$$$$$$$$$$$$$$$$

c:/session/ge031001.fix Jun. 30, 1998 14:14:14



## LEGEND

- GATE (N.O.)
- GATE (N.C.)
- CHECK
- BUTTERFLY (N.O.)
- BUTTERFLY (N.C.)
- THREE-WAY VALVE
- SAFETY OR RELIEF VALVE (OPEN TO ATMOSPHERE)
- MOTOR OPERATOR
- SOLENOID OPERATOR (SINGLE COIL)
- SOLENOID OPERATOR (DOUBLE COIL)
- PISTON OPERATOR
- HORIZONTAL CENTRIFUGAL PUMP
- POSITIVE DISPLACEMENT PISTON PUMP
- FI 0000 SIGHT FLOW INDICATOR
- PULSATION DAMPENER
- DIAPHRAM SEAL
- INTERLOCK
- MATCH MARK - ( DRAWING) MARKS "POINT" TO EACH OTHER AND HAVE SAME LETTER DESIGNATION
- (1) (2) BASIC INSTRUMENT LOCALLY MOUNTED
- (1) (2) LOCAL PANEL OR RACK NO. INSTRUMENT REMOTE MOUNTED
- VFD VARIABLE FREQUENCY DRIVE
- NNF - NORMALLY NO FLOW
- GLOBE (N.O.)
- GLOBE (N.C.)
- KNIFE GATE VALVE (N.O.)
- KNIFE GATE VALVE (N.C.)
- DIAPHRAM VALVE (N.O.)
- DIAPHRAM VALVE (N.C.)
- PINCH VALVE (N.O.)
- PINCH VALVE (N.C.)
- DIAPHRAM OPERATOR
- BALL VALVE (N.O.)
- BALL VALVE (N.C.)
- F.O. - FAIL OPEN
- F.C. - FAIL CLOSED
- F.L. - FAIL LOCKED
- F.A.I. - FAIL AS IS
- VERTICAL CENTRIFUGAL PUMP
- REDUCER
- FLANGED JOINT
- MOTOR DRIVEN AGITATOR
- ACCUMULATOR
- TEMPORARY STRAINER
- EXPANSION JOINT
- RED. EXPANSION JOINT
- RESTRICTING ORIFICE
- HS 0000 CONTROL SWITCH (LOCAL)
- CS 0000 CONTROL SWITCH (CRT SCREEN)

(B-3) — MATCHING DRAWING COORDINATE (TOP OR BOTTOM)
GE-000000 — MATCHING FLOW DIAGRAM

WLS-1-423 -3-4135
FLUID CODE
SYSTEM
UNIT NO.
LINE SPECIFICATION
LINE SIZE

## INSTRUMENTATION

| FIRST LETTER | | SUBSEQUENT LETTERS | |
|---|---|---|---|
| A | ANALYSIS | A | ALARM |
| C | CONDUCTIVITY | C | CONTROLLING |
| D | DENSITY | D | AUXILIARY DEVICE |
| E | ELECTRICAL | E | ELEMENT |
| F | FLOW | G | GLASS OBSERVATION |
| H | HAND | I | INDICATING |
| K | TIME | M | METER |
| L | LEVEL | Q | INTEGRATING (QUANTITY) |
| M | MOTION VIBRATION | R | RECORDING |
| P | PRESSURE | S | SWITCH |
| S | SPEED | T | TRANSMITTING |
| T | TEMPERATURE | V | CONTROL VALVE |
| V | VISCOSITY | X | TEST CONNECTION |
| W | WEIGHT | Y | RELAY |
| Z | POSITION | | |

## INSTRUMENT LINE SYMBOLS

- ELECTRICAL SIGNAL
- PNEUMATIC SIGNAL
- CAPILLARY TUBING
- INTERNAL SYSTEM LINK (DCS SOFTWARE)

NOTE:

1. CAMFLOW STYLE VALVE

REFERENCES:

1. CONTROL LOGIC DIAGRAMS
GC-033039 - TRAIN 1
GC-033042 - TRAIN 2

| MECH. | ELECT. | STRUCT. | I & C | STRESS |
|---|---|---|---|---|
| DRAWN BY | CHECKED BY | ENGINEER | SUPERVISING ENGINEER | |

G/C NO. 6410 0 435 0323 025

| SYM | ZONE | REVISION | DATE | BY | CHK | APP |
|---|---|---|---|---|---|---|
| 4 | | REVISED AS INDICATED | 02/94 | MLH | | |
| 3 | | REVISED AS INDICATED | 10/93 | MLH | WTB | ELB |
| 2 | | REVISED AS INDICATED | 04/93 | PJM | N/A | ELB |
| 1 | | REVISED EQUIP. TAG NOS. | 10/92 | GLD | N/A | RCC |
| 0 | | ISSUED FOR DESIGN | 9/92 | GLD | N/A | RCC |

CADD DRAWING DO NOT REVISE MANUALLY

DRAWN BY: / / DESIGNED BY: / /
CHECKED BY: / /
DRAFTING / / DESIGN / /
ENGRG / /
RELEASE APPROVAL / /
AUTHORIZED BY / /
MATERIAL OR SPEC

NYSEG
GENERATION DEPT.
BINGHAMTON, N. Y.

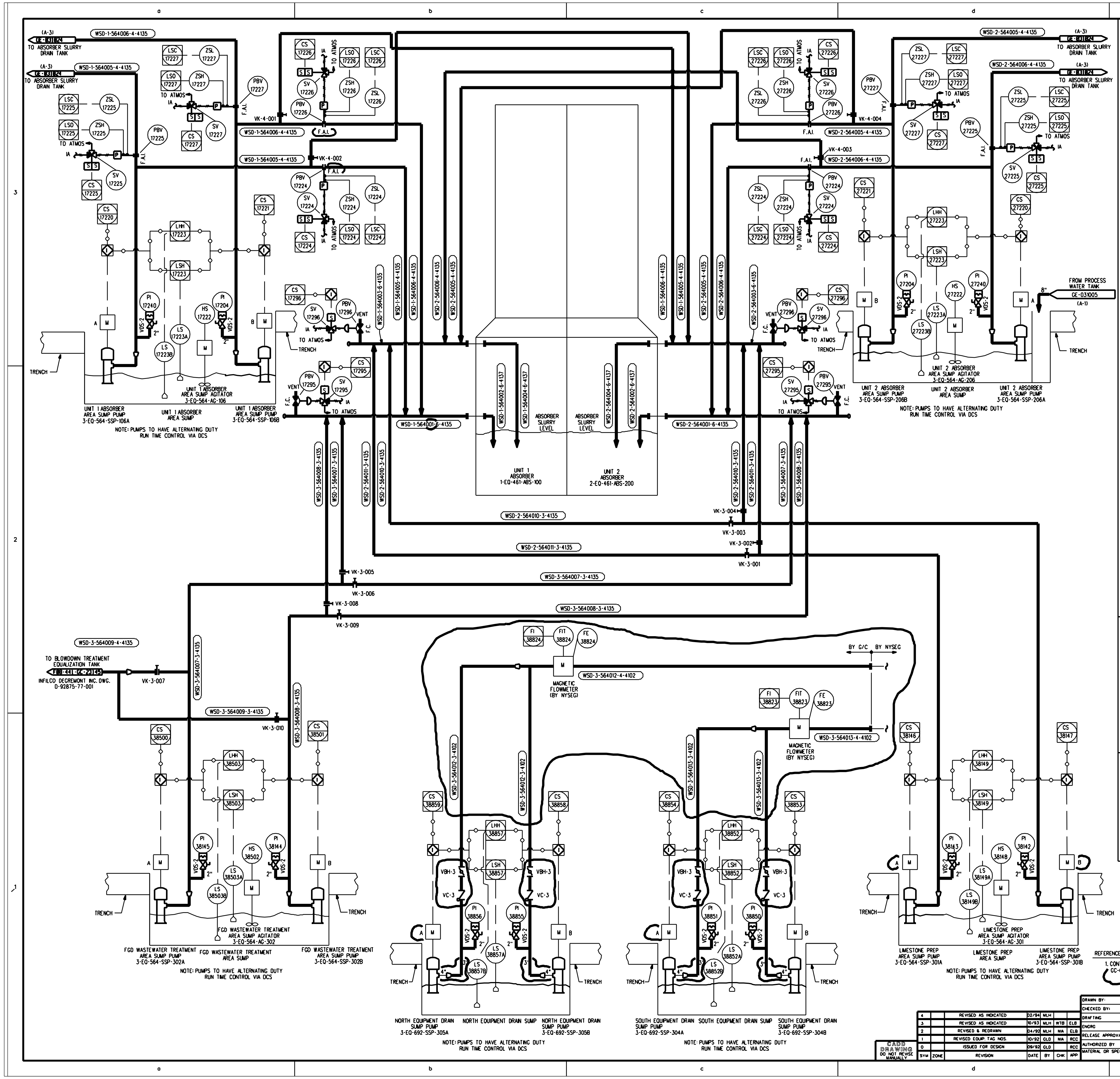
TITLE CLARIFIED WATER
P&ID
FLUE GAS DESULFURIZATION SYSTEM
MILLIKEN /UNIT 1& 2

SCALE NONE
DWG NO GE-031025 4

DIR: 265003

DGNSPEC SYTIME

q:/a6361/ge031025.dgn Jun. 30, 1998 14:27:54



## LEGEND

⋈ GATE (N.O.)
GATE (N.C.)
CHECK
BUTTERFLY (N.O.)
BUTTERFLY (N.C.)
THREE-WAY VALVE
SAFETY OR RELIEF VALVE (OPEN TO ATMOSPHERE)
M MOTOR OPERATOR
S SOLENOID OPERATOR (SINGLE COIL)
S S SOLENOID OPERATOR (DOUBLE COIL)
P PISTON OPERATOR
HORIZONTAL CENTRIFUGAL PUMP
POSITIVE DISPLACEMENT PISTON PUMP
FI 0000 SIGHT FLOW INDICATOR
PULSATION DAMPENER
DIAPHRAM SEAL
◇ INTERLOCK
MATCH MARK - (DRAWING) MARKS "POINT" TO EACH OTHER AND HAVE SAME LETTER DESIGNATION
(1) (2) BASIC INSTRUMENT LOCALLY MOUNTED
(1) (2) LOCAL PANEL OR RACK NO. INSTRUMENT REMOTE MOUNTED
VFD VARIABLE FREQUENCY DRIVE
NNF - NORMALLY NO FLOW

GLOBE (N.O.)
GLOBE (N.C.)
KNIFE GATE VALVE (N.O.)
KNIFE GATE VALVE (N.C.)
DIAPHRAM VALVE (N.O.)
DIAPHRAM VALVE (N.C.)
PINCH VALVE (N.O.)
PINCH VALVE (N.C.)
DIAPHRAM OPERATOR
BALL VALVE (N.O.)
BALL VALVE (N.C.)
F.O. - FAIL OPEN
F.C. - FAIL CLOSED
F.L. - FAIL LOCKED
F.A.I. - FAIL AS IS
VERTICAL CENTRIFUGAL PUMP
REDUCER
FLANGED JOINT
M MOTOR DRIVEN AGITATOR
ACCUMULATOR
TEMPORARY STRAINER
EXPANSION JOINT
HS 0000 CONTROL SWITCH (LOCAL)
CS 0000 CONTROL SWITCH (CRT SCREEN)

(B-3) GE-000000
MATCHING DRAWING COORDINATE (TOP OR BOTTOM)
MATCHING FLOW DIAGRAM

WLS-1-423 -3-4135
FLUID CODE
SYSTEM
UNIT NO.
LINE SPECIFICATION
LINE SIZE

## INSTRUMENTATION

| FIRST LETTER | | SUBSEQUENT LETTERS | |
|---|---|---|---|
| A | ANALYSIS | A | ALARM |
| C | CONDUCTIVITY | C | CONTROLLING |
| D | DENSITY | D | AUXILIARY DEVICE |
| E | ELECTRICAL | E | ELEMENT |
| F | FLOW | G | GLASS OBSERVATION |
| H | HAND | I | INDICATING |
| K | TIME | M | METER |
| L | LEVEL | Q | INTEGRATING (QUANTITY) |
| M | MOTION VIBRATION | R | RECORDING |
| P | PRESSURE | S | SWITCH |
| S | SPEED | T | TRANSMITTING |
| T | TEMPERATURE | V | CONTROL VALVE |
| V | VISCOSITY | X | TEST CONNECTION |
| W | WEIGHT | Y | RELAY |
| Z | POSITION | | |

## INSTRUMENT LINE SYMBOLS

ELECTRICAL SIGNAL
PNEUMATIC SIGNAL
CAPILLARY TUBING
INTERNAL SYSTEM LINK (DCS SOFTWARE)

REFERENCES:
1. CONTROL LOGIC DIAGRAMS GC-033036

Gilbert Commonwealth Companies

| MECH. | ELECT. | STRUCT. | I& C | STRESS |
|---|---|---|---|---|
| DRAWN BY | CHECKED BY | ENGINEER | SUPERVISING ENGINEER | |

G/C NO. 6410-0-564-302-027

| SYM | ZONE | REVISION | DATE | BY | CHK | APP |
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| 4 | | REVISED AS INDICATED | 02/94 | MLH | | |
| 3 | | REVISED AS INDICATED | 10/93 | MLH | WTB | ELB |
| 2 | | REVISED & REDRAWN | 04/92 | MLH | NIA | ELB |
| 1 | | REVISED EQUIP. TAG NOS. | 10/92 | GLD | NIA | RCC |
| 0 | | ISSUED FOR DESIGN | 09/92 | GLD | | RCC |

CADD DRAWING DO NOT REVISE MANUALLY

DRAWN BY: / / DESIGNED BY: / /
CHECKED BY: / /
DRAFTING / / DESIGN / /
ENGRG / /
RELEASE APPROVAL / /
AUTHORIZED BY / /
MATERIAL OR SPEC

NYSEG
GENERATION DEPT.
BINGHAMTON, N. Y.

TITLE
SUMPS & DRAINS
P&ID
FLUE GAS DESULFURIZATION SYSTEM
MILLIKEN /UNIT 1& 2

SCALE NONE
DWG NO GE-031027 4

DIR: 265003

DGN$SPEC$$$$SYTIME$$$$$

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# 3.0 UPDATE OF THE PUBLIC DESIGN REPORT

## 3.1 DESIGN AND EQUIPMENT CHANGES

### 3.1.1 INTRODUCTION

The purpose of this section is to identify and discuss changes which were made to the design and/or equipment of the Milliken Clean Coal Technology Demonstration Project subsequent to the issuance of the Public Design Report. Changes were made in the following systems:

- Flue Gas System
- Makeup, Wall Wash and Quench
- Process Water Tanks and Pumps
- Absorber Recycle Pumps
- Mist Eliminators
- Oxidation Air
- Formic Acid
- Limestone Handling and Preparation
- Gypsum Dewatering
- FGD Wastewater Treatment
- Evaporator/Brine Concentrator System
- FGD Building Sumps and Drains
- NOxOUT® SNCR System
- Heat Pipe Air Heater
- Plant Economic Optimization Advisor

### 3.1.2 FGD SYSTEM

#### FLUE GAS SYSTEM

The FGD flue gas system includes the ID fans, the flue gas dampers and damper seal air systems and flue gas monitoring equipment, all as shown on P&ID GE-031015 (figure 2.6-11). The design of the FGD flue gas system was modified as compared to that described in the Public Design Report. In the original design there were two ID fan damper seal air skids. Each skid provided seal air for two ID fan discharge isolation dampers. Each skid had two seal air fans, one operating and one spare. Because the dampers require seal air only when closed and because the dampers are normally open it was decided that adequate redundancy could be provided with a single seal air skid. Only the Unit 2 skid was installed. Seal air piping was added to connect the Unit 2 skid to the Unit 1 dampers. The Unit 1 skid was maintained as a warehouse spare. This modification resulted in a cost savings to the project. It did not affect the test plan. In addition, to improve access to stack monitoring equipment, a stair was installed from the top elevation in the FGD building into the floor of the stack.

## MAKEUP, WALL WASH AND QUENCH

The FGD system uses process water to quench the flue gas as it enters the absorber vessel. This water is also used to prevent the buildup of solids on the walls of the absorber, in the quench zone, and as makeup to the absorber. These systems consist of piping and controls as shown on P&ID GE-031006 (figure 2.6-14).

The design of the FGD makeup, wall wash and quench system was modified from that described in the Public Design Report. The amount of water needed to maintain the water balance of the FGD system varies with boiler load, flue gas temperature, fuel composition, byproduct moisture content, etc. The original design sought to optimize the use of makeup water to preserve as much as possible for mist eliminator washing. One part of this strategy was to modulate the flow of quench water to each absorber, maintaining a constant flue gas temperature upstream of the absorption spray zone. The temperature measurements in this zone proved to be erratic, probably due to spray impingement and/or solids buildup on the thermocouples, resulting in instability in the quench water flow control loop. Examination of the mist eliminators after the initial period of operation showed them to be in exceptionally clean condition, mitigating the water balance concerns. The quench control software was modified to achieve an on/off type control with a preset flow rate. This modification stabilized the quench water flow control loop while reserving sufficient water for other process users. There were no hardware costs associated with this modification.

## PROCESS WATER TANKS AND PUMPS

The process water tank and pumps system provides process water to the FGD absorbers for mist eliminator washing, flue gas quenching, absorber vessel wall washing and water makeup. The system also provides gypsum filter cake wash water to the centrifuges, makeup water to the clarified water tanks and water for equipment cooling, instrument purging and service hose stations. Makeup water is supplied to the system from the existing plant's process water treatment system. The backup water supply is the existing plant's house service water system. When available, distillate from the evaporator/brine concentrator system is used as makeup to the process water tank and pumps system. The system, as illustrated on P&ID GE-031005 (figure 2.6-15), consists of a single 27,000 gallon tank and three centrifugal pumps, one dedicated to each absorber module and a common spare.

The process water tank and pumps system was modified as compared to that described in the Public Design Report. The demand for process water varies over a wide range of flow rates primarily because the major uses of process water (mist eliminator and gypsum filter cake washing) are intermittent. To maintain the process water pump discharge flow rate above its minimum recommended value, a minimum flow recirculation line is provided. A restriction orifice is provided in the recirculation line downstream of the automatic recirculation block valve to limit the amount of flow through the line. Insufficient resistance in the recirculation line could result in inadequate process water supply pressure and/or excessive velocity in the recirculation line. The process water pump could run out on its curve, overloading its motor. Line loss calculation checks performed late in the design process after pipe routings and user demands had been finalized dictated a larger required differential pressure than could be accommodated by a single restriction orifice. Additional restriction orifices were provided in each recirculation line. The modification allows the process water pumps to operate within the recommended flow range and to maintain adequate process water supply pressure regardless of system demand. This modification resulted in additional cost to the project.

As noted above, the process water tank and pumps system provides makeup water to the clarified water tanks and to the FGD absorbers. An automatic block valve is provided in the water line to each clarified water tank and absorber vessel. Unless sufficient resistance is provided in these lines opening one or more of these valves would result in inadequate process water supply pressure to the other users in the system. In addition, the process water pump could run out on its curve, overloading its motor. Late in the design process pressure reducing stations were added in the process water supply lines to the absorber vessels and clarified water tanks. The modification allows the process water pumps to operate within the recommended flow range and to maintain adequate process water supply pressure regardless of system demand. This modification resulted in additional cost to the project.

Neither of these design modifications had an effect on the test plan.

## ABSORBER RECYCLE PUMPS

Each absorber module is equipped with seven absorber recycle pumps. Each pump supplies recycle slurry to a single absorber spray bank. There are four cocurrent spray banks and three countercurrent spray banks. At design conditions three of the cocurrent banks and two of the countercurrent banks are in operation. The remaining banks and their associated recycle pumps are spares. Refer to P&ID GE-031011 (figure 2.6-12).

The pH of the absorber recycle slurry, a major process variable, is measured by piping a sample line from the discharge of two of the cocurrent recycle pumps to a measurement tank located on an elevated platform adjacent to the absorber module. The sample overflows a weir inside the measurement tank and returns by gravity to the absorber. The size of the return line, as reported in the Public Design Report, was 4-inches. Final hydraulic analysis indicated that a 3-inch line size would be adequate. A 3-inch line was installed in the field and was proven adequate during initial operation. This modification resulted in a cost savings to the project. It did not affect the test plan.

As described in the Public Design Report, two pH probes were to be installed in each pH measuring tank. Control logic was provided to advise the operator when the pH readings were in disagreement, indicating an error in one of the readings. The operator would have had to infer which reading was correct through observing the behavior of other process variables and through the results of grab sample analyses. In order to provide a more positive means of detecting a false reading the design was modified to add a third pH probe. Auctioning software was added to automatically deselect a pH reading and advise the operator if it disagreed with the other two readings. In addition, abrasion in the measuring box caused it to leak. The box was replaced with a fiberglass flow-through piping system. These modifications resulted in improved reliability at a modest additional cost to the project. The modifications did not affect the test plan.

## OXIDATION AIR

The oxidation air system supplies compressed air to the absorbers to react with the bisulfite in the absorber slurry to form gypsum. The system, as illustrated on P&ID GE-031009 (figure 2.6-10), consists of three oxidation blowers (one per absorber module and a common standby) which draw outside air through intake filter silencers and deliver it through a piping manifold to the four air lances in each absorber module. The lances discharge the air in front of the absorber agitator impellers for dispersal into the absorber slurry.

The design of the oxidation air system was modified as compared to that described in the Public Design Report. The piping from the air intake filter silencers and the oxidation blowers was specified to be constructed of carbon steel. The manufacturer's service representative recommended that the piping material be upgraded to prevent rust particles from being pulled into the blowers, possibly shortening their service life. The piping was replaced with galvanized material at additional cost to the project. The galvanized material will resist rusting compared to carbon steel, which should result in improved service life for the blowers. This modification did not affect the demonstration test plan.

## FORMIC ACID

Formic acid is a performance enhancing additive used by the FGD system. The formic acid system receives delivery of formic acid from tanker trucks, provides on-site storage and meters acid to the absorber vessels. The system, as depicted on P&ID GE-031010 (figure 2.6-9), consists of a truck unloading station, a storage tank, metering pump skid and spill containment sump inside the formic acid room, and associated piping and controls.

The design of the formic acid system was modified as compared to that described in the Public Design Report. A spill containment dike and sump are provided to contain formic acid in the event of failure of the formic acid storage tank or feed pumps but no alarm was provided to alert an operator of such an event. A sump level alarm was added to address this deficiency at additional cost to the project. If failure of the tank or feed pumps results in spillage of acid the sump level alarm will notify the operator. This modification did not affect the demonstration test plan.

## LIMESTONE HANDLING AND PREPARATION

The limestone handling and preparation systems transfer crushed limestone from the storage pile north of the FGD building to day storage bins inside to the building. The limestone is then ground in the wet ball mills, classified for required particle size distribution, diluted to the required consistency and stored for use by the FGD system.

### Limestone Preparation Slurry Classification System

The limestone preparation slurry classification system processes the product slurry from the ball mills, returning oversize product to the mills for additional grinding and transferring acceptably sized product to the fresh slurry tanks for use by the FGD system. The system also dilutes the mill product to the required consistency. The system, as shown on Fuller P&ID's 135-92-4-3601, sheets 3 and 4 (figures 2.6-3 and 2.6-4), includes the agitated mill product tanks, the mill product pumps, the limestone classifiers and the distribution boxes.

The limestone preparation slurry classification system was modified as compared to that described in the Public Design Report. Each limestone grinding mill has two mill product pumps, one operating and one standby. When a mill product pump shuts down it is automatically flushed with clarified water. After the pump's suction and discharge isolation valves have closed and its suction line drain valve has opened, the flush valve opens, injecting flush water into the discharge line between the pump and its discharge valve, flushing backwards through the pump. In the design reported in the Public Design Report a separate flush water supply line with an automatic flush valve was provided to inject clarified water into the mill product pump discharge manifold. When both mill product pumps were shut down this additional automatic flush valve would have opened to rinse out the line carrying limestone slurry to the classifiers. Late in the design process it was recognized that this additional automatic flush line was unnecessary as its function could be performed by the mill product pump flush valves through modifications to the control logic. The mill product pump discharge manifold flush line was deleted and the control logic modified to enable flushing of the discharge manifold by operation of the mill product pump flush valves. This modification maintained adequate flushing capability at a cost savings to the project. This modification did not effect the test plan.

As described in the Public Design Report, the gravity flow recycle pipeline from the limestone mill classifier distribution box to the mill product tank was to be 6-inch diameter. Final hydraulic calculations showed that an 8-inch line was required. An 8-inch line was installed. The 8-inch line proved to have the necessary hydraulic capacity. The modification had no differential cost to the project as the limestone mill manufacturer was obligated to provide piping suitable for his process. This modification had no impact on the test plan.

## GYPSUM DEWATERING

Gypsum solids produced in the FGD absorber are removed from the process by the gypsum dewatering system. The gypsum is concentrated and then dewatered, washed to remove chlorides and other dissolved contaminants and exported from the plant. The process liquor is recycled to the process. Slurry from the absorber is fed to the primary hydrocyclones by the bleed pumps. The primary hydrocyclones concentrate the gypsum solids in the bleed stream prior to dewatering in the gypsum centrifuges. Overflow from the primary hydrocyclones is collected in the secondary hydrocyclone feed tanks. Overflow from the secondary hydrocyclone feed tanks is collected in the filtrate tanks. The secondary hydrocyclones remove residual suspended solids from the primary hydrocyclone overflow stream, producing clarified water which is used for limestone preparation, process blowdown and process flushing. Underflow from the secondary hydrocyclones, excess clarified water, and filtrate from the centrifuges are also collected in the filtrate tanks.

### Gypsum Dewatering-Filtrate System

The filtrate system returns the process liquor collected in the filtrate tank to the FGD absorbers. The filtrate system consists of two agitated tanks, two variable speed pumps and associated piping and controls as shown on P&ID GE-031001 (figure 2.6-21).

The filtrate system was modified as compared to that described in the Public Design Report. The filtrate pumps are equipped with variable speed drives. The pump speed is varied to maintain preset level in the filtrate tank. Filtrate tank level was measured by sonic-type level sensors. Level sensor readings proved to be erratic and unreliable which led to periodic cavitation of the filtrate pumps due to low level operation. The sonic level controls were replaced with diaphragm type pressure transmitters mounted on the filtrate tank wall. This modification stabilized the operation of the filtrate pumps, eliminating the cavitation problem. This modification resulted in additional cost to the project but did not impact the test plan.

### Gypsum Dewatering System-Bleed Pumps, Primary and Secondary Hydrocyclones

The gypsum dewatering-bleed pumps, primary and secondary hydrocyclones system consists of four bleed pumps (two per absorber module, one operating and one spare), two primary hydrocyclone clusters, two agitated secondary hydrocyclone feed tanks, two secondary hydrocyclone feed pumps, two secondary hydrocyclone clusters and associated piping and controls. Refer to P&ID's GE-031003, GE-031004 and GE-031008 (figures 2.6-16, 2.6-17 and 2.6-18).

The gypsum dewatering-bleed pumps, primary and secondary hydrocyclones system was modified as compared to that described in the Public Design Report. Slurry sampling connections were added to the bleed system downstream of the bleed pumps. These connections were used to draw samples of the primary hydrocyclone feed slurry. The samples were analyzed for percent solids and particle size distribution as part of optimizing the hydrocyclone vortex finder and apex sizes. This modification resulted in additional cost to the project but did not impact the test plan.

### Gypsum Dewatering System-Centrifuges

Gypsum solids in the absorber bleed stream are concentrated in the primary hydrocyclone underflow and then dewatered in the gypsum centrifuges. Primary hydrocyclone underflow is collected in the centrifuge feed tanks and then fed to the centrifuges by the centrifuge pumps through a continuous feed loop. The centrifuges are batch-operated. Each batch cycle consists of several process steps. In the feed step the centrifuge is charged with slurry while accelerating to 800 rpm. In the spin 1 step the machine continues to rotate at 800 rpm for initial filtration. This is followed by the wash step in which process water is sprayed onto the filter cake for chlorides removal while the centrifuge basket continues to rotate at 800 rpm. In the spin 2 step the centrifuge cake is dried as the centrifuge continues to rotate. In the peel step the filter cake is removed from the centrifuge basket by the peeler knife after the basket has decelerated to 30 rpm. The cake is discharged through a chute to the gypsum conveyor system for transfer to the gypsum storage building. Every several cycles are followed by a heel rinse step in which the interior of the centrifuge is cleaned by flushing with clarified water.

As shown on P&ID's GE-031030 and GE-031031 (figures 2.6-19 and 2.6-20), the gypsum dewatering-centrifuge system consists of two agitated feed tanks, two feed pumps, four centrifuges and associated piping and controls.

The centrifuge system was modified as compared to that described in the Public Design Report. As reported in the Public Design Report, the gypsum dewatering centrifuges are fed from a continuously circulating feed system. This system draws gypsum slurry from the centrifuge feed tank, pumps the slurry in a piping loop past each of the centrifuges and back to the tank. Branch lines from this piping loop feed each individual centrifuge. Because the centrifuges are batch-operated, the flow to each machine is intermittent. A Clarkson muscle-type pinch valve is installed in the return leg of the feed loop to provide adequate back-pressure when a centrifuge feed step is in progress. An automatic bypass around the pinch valve opens at the conclusion of the feed step. This prevents excessive wear of the pinch valve. During startup it was discovered that when the bypass was open, the system resistance was inadequate, causing the feed pump motor to trip on overload. A Clarkson muscle-type pinch valve was installed in the bypass line to limit system flow when the bypass is open. The modification prevents the feed pump motor from overloading when the bypass is open. This modification resulted in additional cost to the project but did not impact the test plan.

The centrifuges are batch-operated machines. A given volume of gypsum solids is processed in each batch. During the centrifuge feed step, the feed valves open and gypsum slurry is loaded into the machine. The centrifuge controls allow the feed valves to be closed either by a timer or by a limit switch which senses when the cake inside the centrifuge basket reaches the desired thickness. The timer is configured as the primary control and the limit switch is the secondary control. The amount of time necessary to load a given amount of gypsum solids into the centrifuge depends on the rate of flow in the centrifuge feed lines and on the solids concentration of the feed slurry. During startup it was recognized that the solids concentration of the feed slurry varied over a wide enough range so that the centrifuge basket could sometimes be filled before the fill timer had timed out. On these occasions the cake thickness limit switch would become the primary feed control. Since overfilling a centrifuge can severely damage the machine, relying only on the cake thickness limit switch posed an unacceptable risk. A density meter was installed in the supply leg of the centrifuge feed piping loop. Control software was added to calculate a required feed duration (feed timer setting) using a known basket cake capacity, a calculated feed flow rate and a measured slurry density. The feed flow rate was calculated from two measurements, the centrifuge feed pump discharge flow rate and the centrifuge feed tank return flow rate. Control software was also added to alert an operator when the difference between the flow rates in the supply and return legs of the centrifuge feed piping loop is too high, indicating an abnormally high centrifuge feed rate. This modification successfully prevented the centrifuge basket from being over-filled, without relying on the cake thickness gauge. The modification also enabled an operator to take corrective action to prevent possible damage to a centrifuge due to over-feeding. This modification resulted in additional cost to the project but did not impact the test plan.

The centrifuge feed isolation valves are Clarkson knife gate valves. By design this style of valve leaks a small amount of process liquor while stroking open and closed. The valves are equipped with a splash guard to collect the fugitive liquor. The splash guard is made of a short section of 2-inch diameter pipe. Piping is provided from the splash guard to the sumps and drain system. Because the centrifuge feed isolation valves open and close for each centrifuge batch the amount of leakage in this service is considerably more than in the other knife gate valve applications. This lead to plugging of the splash guards. To remedy this problem process water was piped to the splash guards to enable periodic flushing. This modification resulted in additional cost to the project but did not impact the test plan.

Automatic drain valves and piping were installed on each feed line to each centrifuge, downstream of the muscle valve to allow drainage of the feed pipe and reduce chloride levels in the gypsum. The valves are slaved to the centrifuge feed valves. This modification resulted in additional cost to the project but did not impact the test plan.

Centrifuge feed tank level was measured by sonic-type level sensors. Level sensor readings proved to be erratic and unreliable which led to periodic cavitation of the centrifuge feed pumps due to low level operation. The sonic level controls were replaced with diaphragm type pressure transmitters mounted on the centrifuge feed tank wall. This modification stabilized the operation of the centrifuge feed pumps, eliminating the cavitation problem.

During the initial period of operation occasional buildup of gypsum occurred in the centrifuge discharge chutes. Pneumatic hammers were added to these chutes to dislodge the gypsum by periodically impacting the chute with the hammers. This modification effectively solved the buildup problem. This modification resulted in additional cost to the project but did not impact the test plan.

### Gypsum Dewatering-Clarified Water System

The secondary hydrocyclones remove residual suspended solids from the primary hydrocyclone overflow stream, producing clarified water which is used for limestone preparation, process blowdown and process flushing. As shown on P&ID GE-031025 (figure 2.6-22), the clarified water system consists of two agitated clarified water tanks, two clarified water pumps, two blowdown pumps and associated piping and controls. During the initial period of operating problems were experienced with the mechanical seals on the blowdown pumps. Rather than replacing the expensive mechanical seals it was decided feed the blowdown pretreatment system from a branch connection from the processing flushing header near the blowdown pretreatment equalization tank. A control valve station was added to the branch connection to control the blowdown flow rate and the blowdown pumps were retired.

## FGD WASTEWATER TREATMENT

The FGD absorbers remove certain other contaminants from the flue gas besides sulfur dioxide. These contaminants, primarily chlorides, metals and residual fly ash not captured by the electrostatic precipitators tend to concentrate in the FGD process liquor. The FGD blowdown treatment system is designed to purge these contaminants from the FGD system. The FGD blowdown treatment system consists of two subsystems, the blowdown pretreatment system furnished by Infilco Degremont Inc.(IDI) and the evaporator/brine concentrator system, furnished by Resources Conservation Co.(RCC).

### Blowdown Pretreatment

As shown in the simplified block flow diagram, figure 2.4-5, the blowdown pretreatment system is fed from the clarified water tank. Clarified water is absorber recycle slurry from which most of the suspended solids have been removed by the primary and secondary hydrocyclones.

The FGD blowdown pretreatment system removes the remaining suspended solids and dissolved solids from the blowdown stream prior to the brine concentration process. The pretreatment process consists of the following steps.

- An agitated equalization tank to balance the FGD wastewater composition and flow.

- pH elevation, calcium sulfate desaturation and magnesium hydroxide precipitation using lime. Sludge is recirculated from the downstream clarifier to aid the desaturation process.

- Secondary precipitation of heavy metals as more insoluble organosulfides using the organosulfide TMT.

- Coagulation with ferric chloride.

- Dosing of flocculation aid (polymer) to the reactor of the Densadeg® unit.

- Flocculation/sludge densification, thickening and final clarification in the Densadeg® unit. The Densadeg® is a three-stage unit comprising a solids-contact reaction zone, a presettler-thickener and lamellar settling tubes in the upper part of the thickener.

- Excess sludge withdrawal, conditioning with lime and dewatering with a plate and frame filter press.

The design of the FGD blowdown pretreatment system was modified as compared to that described in the Public Design Report. The control valves which meter the transfer of clarified water to the FGD blowdown treatment system were to have been provided with open/closed position limit switches to provide valve position feedback to the FGD operators. The valves selected for this service, Clarkson muscle-style pinch valves, cannot be furnished with position limit switches. The limit switches were deleted from the design. Adequate operator feedback is provided by the magnetic flow meter installed in the transfer line. No cost was incurred for this modification and it did not affect the test plan.

In the original design the addition of lime slurry to the pH elevation/desaturation tank was under on/off control in response to pH as measured in the tank. In order to hold a more constant pH value the control of lime slurry was changed to modulating by deleting solenoid valve SV-38520. The pressure boosting FY-38519 was changed from 2:1 to 10:1 in order to be able to fully close the diaphragm style control valve FV-38520 when lime addition is not required. These modifications successfully stabilized the pH at additional cost to the project. The change had no impact on the test plan.

The lime slurry tank was initially furnished without a vent. A vent was added to the tank cover to mitigate the risk of implosion. This modification resulted in additional cost to the project but did not impact the test plan.

The filter press feed pump is a piston diaphragm pump. The pipe support design for the pump discharge piping did not account for the pressure pulsations characteristic of this type of pump. Additional pipe supports were added in the field to stabilize the discharge piping at additional cost to the project. This modification did not affect the test plan.

A common filter press feed pump is provided for both FGD and CPRW/MCW sludge. Air actuated diaphragm valves in the pump's suction manifold connect the pump to the selected sludge storage tank. However, in the event of air pressure failure these valves will partially open, presenting the risk of flow from one sludge storage tank to the other. Manual valves were added in the suction piping to prevent this from occurring. This modification resulted in additional cost to the project. It did not affect the test plan.

### Evaporator/Brine Concentrator

The evaporator/brine concentrator system was designed to process the effluent from the pretreatment system through a vapor-compression type falling-film evaporator, producing a very pure distillate for recycling to the FGD system as process makeup water. The system's by-product calcium chloride brine solution was guaranteed to meet NYSDOT requirements for use in dust control, soil stabilization, ice control and other highway construction related purposes, meeting ASTM D98, Type B (liquid calcium chloride solution) with at least 33% $CaCl_2$.

As shown in the simplified block flow diagram, figure 2.4-6, the pretreated FGD blowdown is conditioned with sulfuric acid and an inhibitor for scale prevention. It is then preheated, deaerated, heated to near boiling and fed to the evaporator sump where it mixes with recirculating, concentrated brine slurry. The slurry is pumped to the brine concentrator (BC) condenser floodbox where it is distributed as a thin film on the inside walls of titanium tubes. As the slurry film flows down the tubes, the water is evaporated. The resulting steam is drawn through mist eliminator pads to the vapor compressor, which raises its saturation temperature to above the boiling temperature of the recirculating brine. The compressed steam is then introduced to the condenser where it gives up its heat of vaporization (to heat the thin film in the inside of the tubes) and condenses on the outside of the tube walls. This condensate is collected in the distillate tank, cooled by heat exchange with the feed stream and returned to the FGD system. As the falling film evaporates, calcium sulfate begins to crystalize. The calcium sulfate seed crystals provide nucleation sites to prevent scaling of the tubes. A side stream of recirculating brine is processed by a hydrocyclone. The underflow is returned to the BC sump. The overflow is either recirculated to the brine concentrator or diverted to the product tank, based upon its dissolved solids concentration. A second side stream of recirculating brine is diverted to the product tank to control the concentration of suspended solids. The 33% brine product is then cooled and transported to market by truck.

The brine concentrator was modified compared to that described in the Public Design Report. Hydrochloric acid was used instead of sulfuric acid for conditioning of the pH of the brine concentrator feed. This was done to minimize the risk of forming calcium sulfate scale in the heat exchangers. The vapor compressor was backfitted after start-up with a check valve to prevent reverse rotation and a backpressure control valve to mitigate excessive vibration. These modifications resulted in additional cost to the project but did not affect the test plan. Operation of the birne concentrator was eventually discontinued due to operating problems. These problems are described in detail in Section 4.8.

## FGD BUILDING SUMPS AND DRAINS

The sump and drain system collects process drains from throughout the FGD system through a network of piping and floor trenches. The process liquor is temporarily stored in area sumps. Sump pumps recycle the collected drainage to the absorbers or transfer it to the absorber drain tank for longer term storage. The system, as depicted on P&ID GE-031027 (figure 2.6-23), consists of a sump adjacent to each absorber module, a sump in the limestone preparation area and a sump in the FGD wastewater treatment area. Each sump is provided with an agitator to maintain slurry solids in suspension and two sump pumps. Two additional sumps, the north and south equipment drain sumps, collect spent cooling water for return to the main plant's wastewater treatment system. These sumps are provided with duplex sump pumps.

The design of the sumps and drains system was modified as compared to that described in the Public Design Report. The equipment drain sump pumps were to have dedicated discharge lines to transfer water to the main plant's low volume wastewater treatment system. However, no flow metering was provided. Late in the design process it was determined that environmental discharge permits required that these flows be metered. The discharge lines from each pair of equipment drain sump pumps were manifolded into a common transfer line to the low volume wastewater treatment system. Each of the two transfer lines was provided with a magnetic flow meter for flow monitoring. Each of the sump pumps was provided with discharge check and block valves to prevent backflow. This modification resulted in additional cost to the project. It did not affect the test plan.

## 3.1.3 NOxOUT® SNCR SYSTEM

NOxOUT® Selective Noncatalytic Reduction (SNCR) technology was to be installed on Unit 2 to provide a further reduction in $NO_X$ emissions over that achieved by the LNCFS 3 combustion modifications alone. The NOxOUT® process, provided by NALCO Fuel Tech, achieves $NO_X$ reduction by the reaction of $NO_X$ with urea injected into the post-combustion zones of the boiler. The urea is injected as an aqueous solution. The quantity of water used for dilution is typically set by the requirement to achieve a good distribution. The urea solution contained in storage normally contains 50% by weight of urea. This solution is then diluted on-line to the concentration for injection which may be in the range of 5 to 20% by weight of urea. In order to avoid scaling of the injectors and to avoid the need for water of high purity for dilution, an anti-scaling additive is used. This permits the use of ordinary service water for dilution. This anti-scalant combined with a dispersant for droplet size optimization is contained in the concentrated urea solution which is marketed under the trade name NOxOUT A®.

The equipment required to deliver the chemical to the injectors is designed based on the specific range of flow rates required, the nature of the control system desired, the amount of air required for atomization and any local construction codes. A modularized approach is used in which the overall delivery system is broken down into five specific segments: storage, recirculation, metering/mixing, distribution and injection.

In 1995, NYSEG received information that the NOxOUT® process had been installed at GPU'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.

### 3.1-4 HEAT PIPE AIR HEATER

The Milliken Station Unit 2 Ljungstrom® type air heaters were replaced with a heat pipe air heater system supplied by ABB Air-Preheater, Inc. to demonstrate the energy savings attainable by using heat pipe technology as a replacement for conventional regenerative and recuperative air heater designs on a utility boiler.

Heat pipe air heaters transfer heat from boiler flue gas to boiler combustion air using an intermediate heat transfer fluid. The heat pipe air heater consists of a series of modules with finned, parallel tubes filled with heat transfer fluids, mounted perpendicular to the gas flow. The heat transfer fluid is sealed inside individual heat transfer tubes which are closed at each end. The tubes are installed with one portion of the tube in the flue gas stream and one portion in the air stream. The heat transfer mechanism is based on the heat transfer fluid operating on its saturation-vapor curve. Each tube provides an intermediate closed-loop evaporation/condensation cycle that is driven by the temperature difference between the hot flue gas and the cold combustion air. On the hot flue gas side, heat is transferred from the flue gas through the tube wall to vaporize the heat transfer fluid (liquid). The vapor travels toward the cold (air side) of the tube, where heat is transferred from the vapor through the tube wall. This heats the combustion air. The vapor inside the tube condenses as it cools while delivering the heat. The condensed liquid in the tube then travels toward the flue gas end where it again vaporizes to repeat the heat transfer cycle. Multiple fluids may be used in one air heater application but only one fluid is used in any one tube (i.e., the fluids are not mixed together).

Installation of a heat pipe provides energy savings in two ways. First, air leakage across the air heater is eliminated, reducing the volume of flue gas that must be handled by the FD and ID fans resulting in lower fan power consumption and increased boiler thermal efficiency (since more heat is transferred to the combustion air). Second, the heat pipe maintains a more uniform exit gas temperature thereby allowing operation at lower average exit gas temperatures while maintaining a safe margin above the acid dew point.

The heat pipe air heater system installed at Milliken was also intended to demonstrate the use of the CAPCIS corrosion monitoring system and air heater gas bypass system to control the air heater discharge temperature. The thermal efficiency of the boiler is maximized while preventing corrosion by controlling the air heater outlet flue gas temperature. The flue gas exit temperature of the heat pipe air heater is adjusted by allowing some of the cold combustion air to bypass the heater through a control damper. Corrosion rate sensors in the flue gas stream downstream of the air heater provide feedback signals to the bypass damper controller. When the corrosion rate gets too high, the control damper modulates open, reducing the heat load and increasing the flue gas exit temperature. In this manner the system adjusts the flue gas exit temperature to the lowest temperature consistent with corrosion prevention. The project intended to demonstrate the energy efficiency and conservation gains achievable by incorporating this total system to maximize the thermal efficiency of the boiler while preventing corrosion. Unfortunately, software problems were encountered with the CAPCIS system during the demonstration which were not resolved at the time of publication of this report.

The design of the heat pipe air heater system was modified as compared to that described in the Public Design Report. After startup, the heat pipe air heater did not perform as well as expected. The flue gas flow from Unit 2 was consistently less than the flow from Unit 1, confirming the expected reduction in leakage across the air heater. However, the exit gas temperature from the Unit 2 heat pipe should have been less than the exit gas temperature from Unit 1. At normal operating conditions, the Unit 2 exit gas temperature was expected to be less than 280 $^{o}$F. The average during one period was 344 $^{o}$F. In an effort to improve performance several design modifications were implemented.

One suspected cause of the under-performance was the presence of impurities in the working fluid in the heat pipe. Such impurities could generate a non-condensable gas at the operating temperature in the heat pipe resulting in a blanketing effect and loss of heat transfer. During the boiler maintenance outage in September and October, 1995, the individual heat pipes were fitted with purge valves. During the boiler startup following the outage, the impurities were bled out of the pipes as the temperature was raised.

Another possible cause of under-performance was believed to be a combination of poor primary and secondary air distribution. During the March 1996 unit outage perforated plates and deflector plates were installed to correct this problem.

Another possible cause of under-performance was believed to be the limited control of primary air temperature. Due to the design range of the fuel delivery system, there is more heat available at times in the primary air section of the heat pipe than the tempering system can adjust for. Dampers were installed on the gas side of the heat pipe. The dampers were modulated to limit the air temperature on the primary side. Installation of dampers also allowed the gas flow to be biased to compensate for any uneven pressure drop differences that may develop across the primary and secondary sides.

Another possible cause of under-performance was believed to be excessive build up on the heat transfer surfaces. The Unit 2 heat pipe experienced relatively high differential pressure on the gas side indicating plugging had developed. This was not unlike the regenerative air heaters which require washing every six months to remove deposits. Two methods were evaluated to clean the heat pipe tubes to prevent fouling. An infra (below audible) sonic sootblower furnished by Infrasonik was installed on the A heat pipe while four new compressed air soot blower lances with special nozzles were installed on the B side. Fouling of the heat pipe has been significantly reduced with the installation of the two soot blowing systems. Infrasonik prepared an acoustic model of the air preheater and the up- and down-stream ducts. This model was used to determine the feasibility of using a device to reduce sound levels in the downstream duct and precipitator resulting in less vibration in the system. Inspections made during a Unit 2 outage (3/4-4/19/97) identified some cracks along the heat pipe interior wall and NYSEG decided to temporarily discontinue the use of the Infrasonik sootblower until a thorough evaluation could be completed. After additional trials the use of the Infrasonic sootblowers was permanently discontinued after additional vibration damage was discovered.

The Heat Pipe operating problems are discussed in detail in Section 4.11.

### 3.1.5 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 evaluate key data emissions parameters, such as $NO_X$, $SO_2$, $O_2$, CO, $CO_2$, 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.

In 1997, the project was modified from that described in the Public Design Report to make PEOA more user friendly, to include two other modules: Monitor and Advisor (developed from an earlier project), and to attach each module with open architecture. The entire package of three modules is called TOPAZ® and consists of the Monitor, Optimizer (i.e., PEOA) and Advisor. The Monitor archives and displays operating data and trends that data. The Advisor provides the logic behind the recommendations given by the Optimizer, and shows any problems with input data to TOPAZ® from the plant. The reason for this change is to make the Optimizer more commercially attractive by making it more user friendly and easily expandable by open architecture design.

## 3.2 DEMONSTRATION PLANT CAPITAL COST UPDATE

The Total Demonstration Project Cost of the Milliken Station Clean Coal Technology Demonstration project, including the three-year demonstration program, were $158,607,000, with DOE contributing $45,000,000. The Total Demonstration Project Capital Costs are summarized by project phase in Table 3.2-1. The three phases of the project included Pre-award and Design, Construction and Demonstration. The costs provided in the subsequent analyses are based on actual costs for the construction phase.

**Table 3.2-1**
**Total Demonstration Project**
**Cost Summary**

| Project Phase | Original Budget |
|---|---|
| Phase I (w/Pre-Award) | $ 11,322,048 |
| Phase II | $118,264,240 |
| Phase III | $ 29,021,519 |
| TOTAL PROJECT | $158,607,807 |

The Total Demonstration Project Capital Costs address the total project scope and goals of the demonstration project, in contrast to the scope of the FGD retrofit alone, which represents a portion of the total project scope. These costs are therefore only appropriate if the intent of use is consistent with accomplishing all of the project's demonstration goals, which are

- 98% $SO_2$ removal efficiency using limestone while burning high sulfur coal
- Up to 70% NOx reduction using the NOxOUT selective non-catalytic reduction (SNCR) technology in conjunction with combustion modifications
- Minimization of solid wastes by producing marketable by-products including commercial grade gypsum, calcium chloride, and fly ash
- Zero wastewater discharge
- Maintenance of station efficiency by using a high-efficiency heat-pipe air heater system and a low-power-consuming scrubber system.

To achieve all of the project's technical objectives, in addition to the FGD system, the $158 million total project cost includes combustion modifications, precipitator modifications, provision for the NOxOUT process, a high-efficiency air heater system and PEOA (Plant Economic Optimization Advisor).

Eliminating the non-FGD scope and costs, the resulting actual FGD demonstration technology capital cost is $79 million, inclusive of engineering and project management, or $264 dollars per kilowatt. The costs in Table 3.2-2 represent procurement and installation which occurred during the project's design and construction phases, and therefore reflect mixed year dollars.

**Table 3.2-2**
**FGD Systems**
**Capital Cost Summary**

| FGD System Titles | Capital $ |
|---|---|
| Limestone Handling & Preparation | $ 5,361,300 |
| Slurry Feed & Recycle | 5,736,900 |
| Absorber Module & Auxiliaries | 6,750,900 |
| Gypsum Dewatering & Handling | 5,337,400 |
| ID Fans & Ductwork | 7,464,600 |
| Waste Water Processing System | 4,484,100 |
| Other Mechanical Systems | 5,356,300 |
| Electrical & I&C | 5,886,400 |
| Stack & Flues | 2,655,800 |
| FGD Building & Site Work | 14,547,500 |
| SUBTOTAL - FGD CONSTRUCTION COST | $ 63,401,200 |
| Engineering/Construction Management | 15,714,900 |
| TOTAL PROJECT CAPITAL COST | $ 79,116,100 |

In addition to the costs of the FGD system, the costs in Table 3.2-2 include a new multiple flue stack with FGD by-pass, new ID fans and ductwork, complete limestone receiving and preparation, complete gypsum handling and storage and a separate waste water treating facility.

The total capital costs of the Milliken Clean Coal Demonstration Project, inclusive of both FGD and Balance of Plant costs, totaled $123,708,100, and are summarized in Table 3.2-3.

**Table 3.2-3**
**Clean Coal Demonstration Project**
**Total Capital Cost Summary**

| FGD System Titles | Capital $ |
|---|---|
| Limestone Handling & Preparation | $ 5,361,300 |
| Slurry Feed & Recycle | 5,736,900 |
| Absorber Module & Auxiliaries | 6,750,900 |
| Gypsum Dewatering & Handling | 5,337,400 |
| ID Fans & Ductwork | 7,464,600 |
| Waste Water Processing System | 4,484,100 |
| Other Mechanical Systems | 5,356,300 |
| Electrical & I&C | 5,886,400 |
| Stack & Flues | 2,655,800 |
| FGD Building & Site Work | 14,547,500 |
| SUBTOTAL - FGD CONSTRUCTION COST | $ 63,401,200 |

### Table 3.2-3
### Clean Coal Demonstration Project
### Total Capital Cost Summary

| FGD System Titles | Capital $ |
|---|---:|
| Coal Mills | 21,436,700 |
| Heat Pipe | 6,182,000 |
| ESP Modifications | 8,432,000 |
| SUBTOTAL - BOP CONSTRUCTION COST | 36,050,700 |
| TOTAL CONSTRUCTION COST | $99,451,900 |
| Engineering/Construction Management | 24,256,200 |
| TOTAL PROJECT CAPITAL COST | $ 23,708,100 |

Project cost elements excluded from Table 3.2-3 include Start-up, Demonstration and Testing, Owner's Project Management and Allowance for Funds During Construction.

## Impact of Design Modifications On Project Capital Cost

Table 3.2-4 summarizes the estimated costs of the design modifications and changes discussed in Section 3.1. The total cost impact of the changes on the total project capital cost was approximately $500,000.

### Table 3.2-4
### Summary Of Estimated Costs Of Design Modifications

| Description | Material $ | Labor $ | Total $ |
|---|---:|---:|---:|
| FGD Flue Gas System | 0 | (21,320) | (21,320) |
| FGD Makeup, Wall Wash and Quench System | 0 | 0 | 0 |
| Process Water Tank and Pumps System | 13,000 | 1,000 | 14,000 |
| Emergency Quench System | 5,076 | 640 | 5,716 |
| Absorber Recycle Pumps | 8,875 | 10,640 | 19,515 |
| Mist Eliminator | 0 | 0 | 0 |
| Oxidation Air System | 0 | 10,673 | 10,673 |
| Formic Acid System | 100 | 2,400 | 2,500 |
| Limestone Prep - Mill Product, Hydroclones, Slurry Distributor System | (2,923) | (640) | (3,563) |
| Gypsum Dewatering - Filtrate System | 3,550 | 6,400 | 9,950 |
| Gypsum Dewatering - Bleed Pumps, Primary & Sec Hydrocyclones System | 2,500 | 320 | 2,820 |
| Gypsum Dewatering - Centrifuge System | 42,062 | 71,200 | 113,262 |
| FGD Blowdown Pretreatment System | 2,482 | 2,380 | 4,862 |
| Brine Concentration System | 45,088 | 38,044 | 83,133 |
| Sumps & Drains System | 7,394 | 3,440 | 10,834 |
| NOxOUT | | | Leased |
| Heat Pipe Air Preheater System | | | NYSEG |
| PEOA | 251,200 | Included | 251,200 |
| **Total - Design Modifications** | **$ 378,404** | **$ 125,177** | **$ 503,581** |

The NOxOut process, originally planned to be installed on Milliken Unit 2, was instead installed on GPU Genco’s Seward Station Unit No. 15 for the purpose of testing and acquiring data associated with NOx reduction. Therefore, capital costs associated with the NOxOUT System are not included in this table, as they were incurred as operational costs (for leased equipment) at the Seward Station. The NOxOUT equipment is not a permanent installation.

## 3.3 OPERATING AND MAINTENANCE COSTS

Total operating and maintenance costs include operating labor, maintenance labor and materials, consumables and by-product credits. The costs are allocated as fixed and variable costs. Fixed operating costs are essentially independent of the number of hours of plant operation. Variable operating costs and consumables, however, are in general directly proportional to the hours of plant operation. The annual operating and maintenance costs presented in this section are based on actual expenditures incurred by NYSEG for Milliken Station Units 1 & 2 FGD systems during operation during the calendar year 1996. Plant operating conditions in 1996 and 1997 are considered to serve as the reference period used for determining annual O&M costs for this FGD demonstration. During 1996, the Milliken Station boilers operated at 93% availability, and the FGD demonstration systems were at peak (100%) availability. Average load for Milliken Unit 1 was 113 MW, and 122 MW for Milliken Unit 2. $SO_2$ removal efficiency for the station averaged 86.9%. The operational data for each Milliken Station unit for 1996 and 1997 are summarized in Table 3.3-1.

**Table 3.3-1**
**FGD Operating Data**

| | **1996** | | | **1997** | | |
|---|---|---|---|---|---|---|
| **Variable** | **Unit 1** | **Unit 2** | **Station** | **Unit 1** | **Unit 2** | **Station** |
| $SO_2$ Inlet Tons | 15,996 | 17,271 | 33,268 | 18,647 | 19,962 | 38,608 |
| $SO_2$ Outlet Tons | 2,286 | 2,061 | 4,347 | 2,844 | 2,683 | 5,527 |
| $SO_2$ Removal Efficiency % | 85.7 | 88.1 | 86.9 | 84.7 | 86.6 | 85.7 |
| Boiler Operating Hours | 8,073 | 8,209 | | 8,151 | 8,049 | |
| Average Load (MW) | 113 | 121 | | 124 | 133 | |
| Scrubber Operating Hours | 7682 | 8063 | | 7,933 | 7,984 | |
| Scrubber Availability % | 100% | 100% | | 99.5 | 100 | |

### 3.3.1 Annual Fixed Operating Cost

Annual fixed operating costs are based on 1997 actual expenditures for the FGD systems at Milliken Station Units 1 & 2. The fixed costs are comprised of operations and maintenance labor and maintenance materials. Operating and maintenance labor costs are dependent on the number of personnel required to operate and maintain the plant. The operations and maintenance labor costs for this period totaled $1,167,050. This value represents a levelized average O&M staff of 5 individuals at a (fully-burdened) average hourly labor rate of $25.70 per hour. In addition, O&M salary costs for the period totaled $275,623. A breakdown of the FGD system fixed costs is presented in Table 3.3-2.

**Table 3.3-2**
**ANNUAL FIXED OPERATING COST**
Reference Year: 1997

| | |
|---|---:|
| Total Annual Operating Labor Costs | $ 602,300 |
| Total Annual Maintenance Labor Costs | 517,800 |
| Total Administrative and Support Salary Costs | 327,400 |
| Total Fixed O&M Costs | $ 1,447,500 |

Maintenance costs for the reference period for balance of plant (BOP) equipment totaled $287,000. The BOP equipment maintenance is co-funded by DOE, but is not a part of the FGD system.

### 3.3.2 Variable Operating Costs

The variable operating costs presented in this section are based on actual consumption rates and actual costs experienced by Milliken Station Units 1 & 2 FGD systems during calendar years 1996 and 1997. The primary operating consumables for the FGD process included limestone and formic acid. During calendar year 1996, limestone consumption totaled 45,329 tons, and formic acid, approximately 152 tons (304,907 lbs) for both units at Milliken Station. Limestone & formic acid consumption totaled 54,744 and 279,820 tons respectively in 1997. A small amount of hydrochloric acid was also utilized in each period. Station service for the FGD systems totaled 33,322 MWh, which is 21% of the total station service used by the Milliken Station.

Costs of the operating consumables including station service for the FGD systems for the years 1996 and 1997 are presented in Tables 3.3-3, and 3.3-4.

## Table 3.3-3
## FGD System Variable Operating Costs
Reference Year 1996

| **Commodity** | **$/Unit** | **Quantity/ Hr** | **Cost $/Hour** | **Cost $/Ton of $SO_2$ Removed** | **Total Hours In Service** | **Total Cost** |
|---|---|---|---|---|---|---|
| Formic Acid | .53 | 34.70/Lb. | 18.43 | 5.60 | 8,785 | $ 161,989 |
| Limestone | 19.66 | 5.16/Ton | 101.48 | 30.82 | 8,785 | $ 891,586 |
| Hydrochloric Acid | NA | NA | .81 | .24 | 8,785 | $ 7,130 |
| Lime (Waste Water Treatment) | 79.58 | .12/Ton | 9.55 | 2.90 | 8,785 | $ 83,960 |
| Metal Sludge | $20.32 | .26/Ton | 5.32 | 1.61 | 8,785 | $ 46,706 |
| Station Service (Electric Power) | .016 | 3,793/KWH | 61.00 | 18.53 | 8,785 | $ 535,946 |
| TOTAL VARIABLE OPERATING COSTS | | | | | | $ 1,727,317 |

**Table 3.3-4**
**FGD System Variable Operating Costs**
Reference Year 1997

| Commodity | $/Unit | Quantity/ Hr | Cost $/Hour | Cost $/Ton of $SO_2$ Removed | Total Hours In Service | Total Cost |
|---|---|---|---|---|---|---|
| Formic Acid | .42 | 31.94/Lb. | 13.42 | 3.55 | 8,760 | $ 117,641 |
| Limestone | 18.18 | 6.24/Ton | 113.64 | 30.09 | 8,760 | $ 995,488 |
| Hydrochloric Acid | NA | NA | .86 | .23 | 8,760 | $ 7,560 |
| Lime (Waste Water Treatment) | 80.82 | .06/Ton | 5.05 | 1.34 | 8,760 | $ 44,291 |
| Metal Sludge | $16.01 | .23/Ton | 3.75 | 1.00 | 8,760 | $ 32,918 |
| Station Service (Electric Power) | .016 | 3,676/KWH | 58.67 | 15.54 | 8,760 | $ 514,000 |
| TOTAL VARIABLE OPERATING COSTS | | | | | | $ 1,711,898 |

The total variable operating cost per ton of $SO_2$ removed decreased from $59.70/ton in 1996 to $51.75 per ton in 1997.

### 3.3.3 By-products

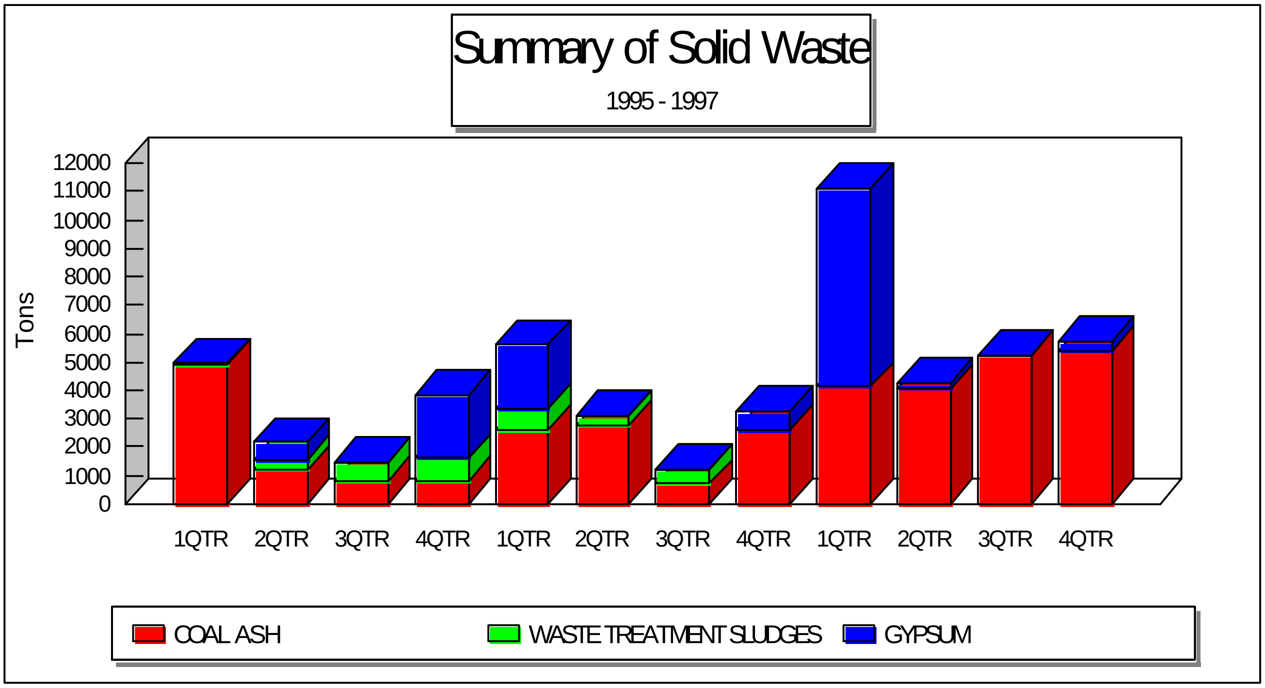
The only saleable by-product resulting from the FGD demonstration process was gypsum. Total gypsum produced in 1996 was 84,773 tons. The saleable gypsum quantity increased to 97,104 tons in 1997. Expenses associated with the sale of gypsum exceeded revenues received from the sales of gypsum, however, due to the high costs of transporting the gypsum to its market. The net costs associated with the sale/disposal of the gypsum totaled $457,770 or $5.40 per ton, for the reference year 1996. This expense declined to $383,592, or 3.95 per ton in reference year 1997. Other Milliken Station by-products included flyash and bottom ash. Revenue obtained from sale of flyash and bottom ash totaled $123,176 in 1996 and $159,574 in 1997.

No calcium chloride was produced for commercial sale during the demonstration period due to the technical problems experienced with the brine concentrator.

A summary of by-product sales for the period January 1995 through September 1996 is presented below in Figure 3.3-1.

Flyash disposal was initially high, and sales low, due to the tuning of the LNCFS-3 burners. Flyash disposal dropped off during the course of the year as optimization of the burners was finalized, and sales increased.

**Figure 3.3-1**



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 onsite 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 flyash was immediately sold to be used in concrete mixes.

During 1995 and the first half of 1996, gypsum disposal was required due to the problems experienced with the centrifuges. In general, 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. As can be seen in Figure 3.3-1, during the second quarter of 1996, there was a significant decrease in the costs associated with gypsum disposal. The decrease in costs was directly related to the increased sales of gypsum resulting from NYSEG's negotiation of a final purchase agreement with a Canadian wall board manufacturer.

### 3.3.4 Waste Water Treatment

Lime consumption for waste water treatment totaled 1,025 tons in 1996. Consumption decreased to 548 tons in 1997. The waste water treatment systems produced 2,298 tons of metal sludge, and 189,110 gallons of brine in 1996, and 2,056 tons of metal sludge and 28,463 gallons of brine in 1997. The cost of disposal for the metal sludge was $46,706, or $20.32 per ton in 1996 and $16.01 in 1997. Sludge disposal costs increased initially as a result of starting up the FGD brine feed water treatment and both FGD modules becoming operational.  Brine production decreased substantially in 1997 due to the problems encountered with the brine concentrator.

# 4.0 DEMONSTRATION TESTING AND EVALUATION PROGRAM

## 4.1 INTRODUCTION

The demonstration testing and evaluation program was designed to characterize the performance of the various demonstration technologies. The program goals were to: (1) demonstrate the effectiveness of the environmental control and boiler systems at several operating conditions and (2) demonstrate the long term reliability and performance of the systems. The program encompassed a range of evaluations including $SO_2$ and $NO_x$ reduction efficiencies, power consumption, process economics, load following capability, reagent utilization, by-product quality and additive effects. The total time duration required for the program was 36 months.

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

| | |
|---|---|
| 1.03.69.01 | Plant Economic Optimization Advisor (PEOA) |
| 1.03.69.03 | Training Simulation Models for Boiler $NO_X$ Emission & Control at Milliken |
| 1.03.69.05 | CRT-Based FGD Simulator for Milliken |
| 1.03.69.06 | Validation of Brigham Young University 3D Combustion Code |
| 1.03.69.08 | Stebbins Tile Test Facility |
| 1.03.69.09* | Milliken Evaluation of the Hybrid SNCR/SCR $NO_X$ Control Process |
| 1.03.69.10 | Milliken Selective Non-Catalytic Reduction Demonstration |
| 1.03.69.11* | Milliken-Unit 2 Flame Viewing Camera |
| 1.03.69.12* | Milliken-Unit 2 DUCSYS Risk Assessment |
| 1.03.69.13* | Milliken-Innovative Waste Liners |
| 1.03.69.14 | Milliken-Materials of Construction |
| 1.03.69.15 | Milliken-ESP Upgrade Evaluation |
| 1.03.69.16 | Milliken-Flue Gas Desulfurization SHU Process Evaluation |
| 1.03.69.17 | Milliken-Mist Eliminator (Including Wet Stack) Testing |
| 1.03.69.19 | Milliken-Heat Pipe Air Heater Evaluation |
| 1.03.69.20* | Milliken-Ammonia Analyzer |
| 1.03.69.24 | Milliken-LNCFS 3 Evaluation |
| 1.03.69.25* | Milliken-Establishing Vegetative Buffers on Poor Sites |
| 1.03.69.26 | Milliken CCT IV Test Program Management |

Activities marked with an asterisk were part of the demonstration, but not DOE scope of work.

The scope of each of the DOE funded activities is summarized below.

### PLANT ECONOMIC OPTIMIZATION ADVISOR (PEOA)

This program was designed to demonstrate the capability of the PEOA to integrate with the power plant distributed control system, performance monitoring and information systems on a variety of network topologies, operating systems and hardware platforms.

PEOA is a neural networking system utilizing optimization algorithms for evaluating key emissions data parameters such as $NO_x$, $SO_2$ , $O_2$, CO, $CO_2$, carbon in ash and opacity in addition to other operational parameters such as boiler and turbine operation, gypsum sales, emissions credits and coal quality. The system provides "what if" capabilities to allow users to utilize the optimization features to evaluate various operating scenarios.

## TRAINING SIMULATION MODELS FOR BOILER $NO_X$ EMISSION AND CONTROL AT MILLIKEN

The objective of this program was to develop, demonstrate and transfer technology for a simulation model of a coal-fired boiler for use in training operators in emission controls. The emission process and control model provides low cost replica training simulators for use in training plant operators to use emission controls to meet the stringent $NO_X$ environmental regulations. The emission simulation module utilizes a personal computer programmed with detailed process, control and emission models. The simulator provides a tool for control room operators to: study the effect on emissions of the various emission control equipment; develop operating experience, confidence and accuracy in normal and abnormal operation of the emission control equipment; follow specific operating procedures; analyze plant systems, their function and interaction with other systems; learn operation, theory and use of plant controls and practice response and recovery from various malfunctions.

## CRT-BASED FGD SIMULATOR FOR MILLIKEN

The scope of this program included the development and the performance of validation tests of a CRT-based training simulator model for the SHU FGD system.

## VALIDATION OF BRIGHAM YOUNG UNIVERSITY 3D COMBUSTION CODE

The purpose of this program was to evaluate the accuracy of the Advanced Combustion Engineering Center (ACERC) PCGC-3 combustion code to predict key parameters such as $NO_X$ and unburnt carbon in the flyash exiting the boiler. Also included was the development of an empirical model to predict $NO_X$ and unburnt carbon for the Milliken CCTD.

## STEBBINS TILE TEST FACILITY

The purpose of this program was to document the techniques employed in constructing an absorber module, evaluate crack repair, mortar and tile wear, pipe penetrations and monitor operating and maintenance costs. A video was produced to document construction techniques for installation of scrubber walls.

## MILLIKEN SELECTIVE NON-CATALYTIC REDUCTION DEMONSTRATION

The original purpose of this program was to investigate the capability of additional $NO_X$ reduction utilizing SNCR in conjunction with LNCFS-3. Nalco's NOxOUT® process was to be installed at Milliken 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. The NOxOUT® demonstration was eventually relocated to GPU's Seward Station. Because Seward is not equipped with low $NO_X$ burners, the scope of this project had to be limited to evaluating the performance of the NOxOUT® process without upstream $NO_X$ control.

## MILLIKEN MATERIALS OF CONSTRUCTION

This scope of this program included reviewing 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.

## MILLIKEN-ESP UPGRADE EVALUATION

The purpose of this 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 $^oF$ 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 $NO_X$ control. Also assessed were design aspects of the ESP including power consumption, fields, process optimization of T-R controls and final set points.

## MILLIKEN 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 Umwelttichnik (SHU) cocurrent / countercurrent, formic acid enhanced wet limestone process, including associated system components such as the mist eliminator/wet stack and materials of construction. The scope of this program included evaluating absorber module chemistry for limestone grind, formic acid and variations in recycle slurry operation relative to $SO_2$ removal, L/G ratio, pressure drop, formate loss, oxidation air utilization and byproduct gypsum quality.

## MILLIKEN MIST ELIMINATOR (INCLUDING WET STACK) TESTING

The scope of this program included documenting the performance of the full scale mist elimination system including measurements of pressure drop, gas velocity, carryover and droplet size distribution at design conditions and as a function of boiler load and recycle pumps in service. The scope also included documenting the performance of the wet stack including measurements of gas velocity, liquid loading, droplet size distribution and analysis of stack drain composition as a function of boiler load and number of recycle pumps in service.

## MILLIKEN HEAT PIPE AIR HEATER EVALUATION

The objective of this program was to provide an independent evaluation of heat pipe air heater system for the U.S. utility industry. The scope of the study included evaluation of thermal performance for the as-new condition and thermal performance degradation as a result of fouling and after cleaning. Also included were assessments of corrosion of the heater and of coupons of alternate tube materials. The scope included reviewing the economic benefits of the system including the effects of reduced air in-leakage, lower flue gas temperature, smaller cold side primary air fan requirements, etc.

## MILLIKEN LNCFS-3 EVALUATION

The objective of this program was to supplement and confirm earlier demonstrations of the LNCFS-3 low $NO_X$ combustion system for tangentially fired boilers. The program scope included 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 included were assessments of the performance achievable with a complete windbox replacement and the use of dynamic classifiers.

## MILLIKEN CCT IV TEST PROGRAM MANAGEMENT

Aside from its project management and administrative functions the scope of this program included collection and analysis of plant operating data and development of reports addressing operability and reliability and critical component failures.

Each of these programs produced detailed reports of the testing that was conducted and of the demonstration and test results. The following sections of the Project Performance and Economics Report present the accomplishments of each of these programs in summary form. As appropriate, each program’s test plans are discussed along with procedures for operation, instrumentation and data acquisition; test methodology; analyses of feed stocks, products and reagents and data analysis methodology. Important data collected during each test program are summarized. Short-term and long-term results from each program are discussed, including, as appropriate, the effects of process parameters on performance. Correlations of results are presented and their significance is discussed. Readers interested in additional detail are referred to the individual program reports which are available through NYSEG.

## 4.2 PLANT ECONOMIC OPTIMIZATION ADVISOR (PEOA)

The Plant Economic Optimization Advisor (PEOA) is an on-line electronic performance support system (ESPSS) presently under development by NYSEG and DHR Technologies, Inc. The PEOA system is designed 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. This 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.

The PEOA system integrates key aspects of plant information management and analysis to assist plant personnel with optimization of overall plant economic performance, including emissions monitoring and compliance. PEOA will evaluate and optimize all major aspects of plant operation, 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 will also provide 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 is a neural networking system which uses optimization algorithms to evaluate key data emissions parameters, such as $NO_X$, $SO_2$, $O_2$, CO, $CO_2$, carbon-in-ash and opacity, plus other operational parameters such as boiler and turbine operation, gypsum sales, emissions credits, and the impacts of coal quality and coal 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. For example, PEOA will provide advice to help operators take the proper actions to achieve the theoretical optimal performance predicted by the optimization algorithms.

The PEOA is being developed as an “open”, client/server-based system using object-oriented development technologies. Developed in this manner the PEOA will be capable of smoothly integrating with legacy power plant DCS, 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.

Phase1: 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.

### 4.2.1 REPORT OF PEOA TESTING CONDUCTED JAN/FEB 1995

DHR Technologies, Inc. (DHR) developed a Plant Economic Optimization Advisor software package (PEOA) for New York State Electric and Gas Corporation. PEOA runs on a PC platform under the Microsoft Windows operating system and utilizes a Graphical User Interface. PEOA includes a Server program, which runs on Milliken Station's VAX computer. The PEOA Server provides the interface between the Milliken Station WDPF system's PI data base and the PEOA client PC’s. The Server also includes a routine which creates training data files from data stored within the VAX's memory. These training data files provide PEOA with historical plant data which are used in training the NN Model. The PEOA system requirements are defined in a Requirements Traceability Table (RTT), Table 4.2-1.

## Table 4.2-1
## Requirements Traceability Table (RTT)

| Descriptions | | | Requirements | | Traceability | |
|---|---|---|---|---|---|---|
| Item | Aspect | Capability | PEOA | NYSEG | **Test Procedure** | Notes |
| **1.0** | **NYSEG Corporate Capabilities** | **Ability to integrate with and utilize existing NYSEG system environment, including hardware, software and networks.** | Outlined under PEOA topics that follow. | Provision and support of system. | | |
| **1.1** | **Hardware** | **Provision and support of hardware environment.** | NA | Provided by NYSEG | | |
| 1.1.1 | WDPF | WDPF (Rev. 7.0) Digital control system (DCS) and Westnet 11 Data Highway provided from Westinghouse, providing high speed access to control information through PI. | NA | Provided by NYSEG | | |
| 1.1.2 | VAX | VAX 4000, Model 300 Timesharing system with 64 MB RAM (originally 32 MB) , 2 DSSI Adapters with HDs, 1 Ethernet Adapter interfacing with Engineering (CIS) LAN, DCS, VAX/VMS multi-tasking OS serving OPM, Plant Historian, and possibly PEOA. | NA | Provided by NYSEG | | |
| 1.1.3 | DEC PCs | Ethernet LAN running (DECPathworks 4.0) with 10 DEC PCs (80386 and 80486); Novell-based Token Ring LAN, with 16 PCs. | NA | Provided by NYSEG | | |
| 1.1.4 | Printers | Support of simple (ASCII) text printing. | NA | Provided by NYSEG | | |
| **1.2** | **Networks/Paths** | **Provision and support of network environment.** | NA | Provided by NYSEG | | |
| 1.2.1 | Engineering LAN | Milliken Ethernet Engineering LAN and Token Ring Administration LAN and NYSEG MAN bridged allowing communication for interoperability of “one integrated system.” | NA | Provided by NYSEG | | |
| 1.2.2 | Administration LAN | Milliken Ethernet Engineering LAN and Token Ring Administration LAN and NYSEG MAN bridged allowing communication for interoperability of “one integrated system.” | NA | Provided by NYSEG | | |
| 1.2.3 | MAN | NYSEG’s Metropolitan Area Network providing connectivity between Milliken Station and NYSEG's Kirkwood and Vestal offices. | NA | Provided by NYSEG | | |
| 1.2.4 | DCS/Data Highway | WDPF (Rev. 7.0) Digital control system (DCS) and Westnet II Data Highway provided from Westinghouse, providing high speed access to control information through PI. | NA | Provided by NYSEG | | |

## Table 4.2-1
## Requirements Traceability Table (RTT)

| Descriptions | | | Requirements | | Traceability | |
|---|---|---|---|---|---|---|
| Item | Aspect | Capability | PEOA | NYSEG | **Test Procedure** | Notes |
| **1.3** | **Software** | **Provision and support of software environment.** | NA | Provided by NYSEG | | |
| 1.3.1 | OPM | Operator Performance Monitor (OPM) system from Black & Veatch, providing "what-if' models, controllable parameter monitoring, related plant displays and reporting. | NA | Provided by NYSEG | | |
| 1.3.2 | PI | Oil Systems' Plant information (PI) system installed and configured by Westinghouse for data collection, reporting, and trending. | NA | Provided by NYSEG | | |
| **1.4** | **Locations** | **Provision and support of physical environment.** | NA | Provided by NYSEG | | |
| 1.4.1 | Milliken Unit #2 | Installation at physical site. | NA | Provided by NYSEG | | |
| 1.4.2 | Kirkwood Office | Remote corporate office (Kirkwood, Vestal, etc.) access through NYSEG network. | NA | Provided by NYSEG | | |

## Table 4.2-1
## Requirements Traceability Table (RTT)

| Descriptions | | | Requirements | | Traceability | |
|---|---|---|---|---|---|---|
| Item | Aspect | Capability | PEOA | NYSEG | Test Procedure | Notes |
| **2.0** | **Milliken Unit #2 Capabilities** | **Ability to represent and utilize existing or planned plant process information (actual data, constraints, etc.) specifically for Milliken Unit #2.** | Outlined under PEOA topics that follow. | Provision and support of process. | | |
| **2.1** | **Data availability** | **Generation and storage of actual plant process data; manual input of non-calculated values; availability of values through PI. Data is be provided** for the **following areas:** | Utilization of pertinent available data. | Generation, storage, and availability | 2,4 | |
| 2.1.1 | Unit Specific Parameters | Emissions/CEM Parameters,<br>FGD Parameters,<br>Performance Parameters,<br>Fly Ash/Bottom Ash Parameters,<br>Mill Parameters,<br>Electrical Parameters,<br>LOI Parameters,<br>Coal Quality Parameters | Utilization of pertinent available data. | Generation, storage, and availability of data. | 2,4 | |
| 2.1.2 | Cost Parameters | Land Fills,<br>Gypsum,<br>Limestone,<br>NOx/Urea,<br>Formic Acid,<br>Scale Inhibitor,<br>CaCl,<br>Fly Ash | Utilization of pertinent available data. | Generation, storage, and availability of data. | 2,4 | |
| 2.1.3 | Calculation Inputs | Averaged,<br>User Defined,<br>Other | Utilization of pertinent available data. | Generation, storage, and availability | 2,4 | |

## Table 4.2-1
## Requirements Traceability Table (RTT)

| Descriptions | | | Requirements | | Traceability | |
|---|---|---|---|---|---|---|
| Item | Aspect | Capability | PEOA | NYSEG | Test Procedure | Notes |
| **3.0** | **PEOA Performance Assistant Capabilities** | **Utilization of available data for analysis.** | **Detailed below.** | **See Item 2.0.** | | |
| **3.1** | **Modeling** | **Ability to represent and emulate plant processes.** | Detailed below. | Detailed | 5,6 | |
| 3.1.1 | WhatIf | Ability to run "WhatIf" scenarios utilizing available and calculated data. | Provide | NA | 5 | |
| 3.1.2 | Calculations | Ability to perform necessary calculations (e.g., averaged values, costs, model inputs and outputs). | Provide capability. | NA | 5 | |
| 3.1.3 | Optimization | Ability to generate optimized (target) data based upon specified conditions (e.g., actual data, specified constraints). | Provide capability. | NA | 6 | |
| **3.2** | **Analysis** | **Provision of plant process analysis capabilities.** | Detailed below. | NA | 1,6 | |
| 3.2.1 | OPM features not duplicated | Minimal duplication of OPM capabilities, including basic performance monitoring and historical trending. | Capabilities not provided. | Provision of capabilities through | n/a | |
| 3.2.2 | Advice | Provision of advice on plant performance, including recommendations for minimizing costs and background information pertaining to such recommendations. | Provide capability. | NA | 6 | |
| 3.2.3 | Trending | Provision of trending (plotting ) capability for multiple parameters. | Provide capability. | NA | 1 | |

## Table 4.2-1
## Requirements Traceability Table (RTT)

| Descriptions | | | Requirements | | Traceability | |
|---|---|---|---|---|---|---|
| Item | Aspect | Capability | PEOA | NYSEG | Test Procedure | Notes |
| **4.0** | **PEOA Data Coordination Capabilities** | **Acquisition, generation, and management of data.** | **Detailed below.** | **NA** | | |
| **4.1** | **Acquired Data** | **Ability to receive and retrieve data.** | Detailed below. | NA | 1,4 | |
| 4.1.1 | PI Server | Interface with PI for historical or current (relative to a given sampling period) data. | Provide capability. | See 1.3.1 | 4 | |
| 4.1.1 | User Input | Interface with User for information pertaining to data values, resources, and configuration/control of other capabilities. | Provide interface. | Provide User input. | | |
| **4.2** | **Generated Data** | **Ability to generate needed information not acquired.** | Detailed below. | NA | 5,6 | |
| 4.2.1 | Modeling Conditions & Results | Generation of emulated (modeled) plant conditions. | Provide capability. | Provide conditions as appropriate. | 5 | |
| 4.2.2 | Calculations Results | Calculation of additional data from available data. | Provide capability. | NA | 5,6 | |
| 4.2.3- | Optimization Results | Generation of optimal (target) data. | Provide. | NA | 6 | |
| **4.3** | **Management** | **Ability to write, read, and report PEOA system and plant process data.** | Detailed below. | NA | 1 | |
| 4.3.1 | Reporting | Ability to print process data. | Provide | NA | 1 | |
| 4.3.2 | File Resources | Ability to read and write process data. | Provide | NA | 1 | |
| 4.3.3 | ASCII Files & Platform Independence | Ability to adjust (modify) PEOA system through text (ASCII) files. | Provide capability. | NA | 1 | |

## Table 4.2-1
## Requirements Traceability Table (RTT)

| Descriptions | | | Requirements | | Traceability | |
|---|---|---|---|---|---|---|
| Item | Aspect | Capability | PEOA | NYSEG | Test Procedure | Notes |
| **5.0** | **PEOA User Interface Capabilities** | | **Detailed below.** | **NA** | | |
| 5.1 | **Interface Methods** | **Ability to interface with User through input and output devices.** | Detailed below. | NA | 1 | |
| 5.1.1 | Input | Ability to accept and respond to User input through physical devices (keyboard, mouse, etc.), logical devices (files), and graphical devices (windows, menus, buttons, etc.). | Provide capability. | Provide User input. | 1 | |
| 5.1.2 | Output | Ability to relate to User the results of User actions (i.e., PEOA system response) through physical devices (CRT's, printers), logical devices (files), and graphical devices (windows, text, etc.). | Provide capability. | Provide User. | 1 | |
| 5.1.3 | Displays | Ability to utilize graphical devices (windows) for interaction. | Provide capability. | Provide User. | 1 | |
| **5.2** | **Data Information Displays** | **Provision of displays relating information on data as a result of acquisition, modeling, or maintenance.** | Detailed below. | NA | 1 | |
| 5.2.1 | Acquisition | Ability to display resulting data acquired from PI, User input, or PEOA system calculation. | Provide capability. | Provide Data. | 1 | |
| 5.2.2 | Modeling | Ability to display data resulting from “WhatIf” or Optimization capabilities. | Provide | NA | 1 | |
| 5.2.3 | Maintenance | Ability to request logical (disk file**)** storage and retrieval of data. | Provide capability. | Provide disk space. | 1 | |
| 5.2.4 | Report Displays | Ability to request printed results of certain Data Information Displays (specifically ones involving Acquisition or Modeling). | Provide capability. | Provide printer. | 1 | |
| **5.3** | **Analysis Displays** | **Provision of displays activation, control, and configuration of the following analysis capabilities: "WhatIf", Optimization, Advice (Advisor), and Trending.** | Detailed below. | NA | 1, 5,6 | |
| 5.3.1 | WhatIf | Ability to activate, configure, and control “WhatIf” capability. | Provide | NA | 1,5 | |
| 5.3.2 | Optimization | Ability to activate, configure, and control Optimization capability. | Provide | NA | 1,6 | |
| 5.3.3 | Advisor | Ability to display Advisor recommendations and access background information. | Provide capability. | NA | 1 | |
| 5.3.4 | Trending | Ability to activate, control, and configure multi-point and multi-dimensional trending plots. | Provide capability. | NA | 1 | |
| **5.4** | **Administration** | **Ability to activate Administrative capabilities (not formally** | Provide | NA | 1 | |

## Table 4.2-1
## Requirements Traceability Table (RTT)

| | | | | | | |
|---|---|---|---|---|---|---|
| | **Displays** | **specified).** | capability. | | | |
| **5.5** | **Help Displays** | **Ability to display supplemental information on PEOA system usage.** | Provide capability. | NA | 1 | |

## Table 4.2-1
## Requirements Traceability Table (RTT)

| Descriptions | | | Requirements | | Traceability | |
|---|---|---|---|---|---|---|
| Item | Aspect | Capability | PEOA | NYSEG | Test Procedure | Notes |
| **6.0** | **PEOA User Capabilities** | **Ability to access PEOA system capabilities according to User classification (given below).** | **Provided through User interface** | **Provision of personnel.** | | |
| **6.1** | **Plant Personnel** | **Ability for personnel from the plant (unit) to access standard capabilities (through displays listed above).** | Provided through User interface. | Provision of personnel. | 3 | |
| 6.1.1 | Plant Operators | Ability **to** access basic Acquisition and Optimization capabilities. | Provided through User interface. | Provision of personnel. | 3 | |
| 6.1.2 | Plant Engineers | As Plant Operator with addition of advanced Analysis capabilities. | Provided through User interface. | Provision of personnel. | 3 | |
| 6.1.3 | Plant Managers | As Plant Engineer with addition of Administration capabilities. | Provided through User interface. | Provision of personnel. | 3 | |
| **6.2** | **System Personnel** | **Ability to access PEOA system resources (nominally through external interfaces).** | Provided through User interface. | Provision of personnel. | 3 | |
| 6.2.1 | System Operator | Ability to modify system configuration through resources. | Provided through User interface. | Provision of personnel. | 3 | |
| 6.2.2 | System Developer | As System Operator with addition of modification of executable binary (code). | Provision of personnel. | NA | 3 | |
| **6.3** | **Corporate Personnel** | **As (a remote) Plant Manager.** | Provided through User interface. | Provision of personnel. | 3 | |

Test Plan Version 1.0 was executed on January 31st, February 1st and 2nd 1995, and included tests PEOA-TP-001 through PEOA-TP-005. All five tests were designed to demonstrate that PEOA software complies with all of the requirements identified within the Requirements Traceability Table. These tests were used for formal final acceptance testing of the PEOA software.

The initial PEOA tests were conducted using data available from Milliken Station Unit 1. The test procedures were designed to evaluate PEOA functions that could be analyzed with the available data. Where meaningful, manual input of unavailable process variable data was used to simulate unavailable system parameter measurements (e.g., Coal Heating Value, Unit Cost of Coal, Sales Value of Electrical Power, etc.). These values are required for the calculation of Plant Earnings. The Optimizer uses Plant Earnings to determine Optimal Target Values (settings) for operator controllable Process Input Parameters.

PEOA testing was performed in two separate stages. The first stage tested PEOA system hardware and software installed at Milliken Station and encompassed Test Procedures 1, 2, 3, and 4. The test director for the first stage was a DHR employee. A NYSEG representative was assigned as an observer to validate the testing of tests 1 through 4. The second stage required plant operators to change plant operating parameters; therefore, a NYSEG representative acted as the test director. The second stage was performed by DHR test engineers and Milliken Station operations personnel, and encompassed test procedure 5.

In all cases the test director was responsible for the following:

- Ensuring availability of the required hardware and software
- Ensuring availability of other required test personnel
- Test scheduling
- Test startup and conduct
- Evaluation of test results
- Deciding whether testing should continue following a test failure
- Ensuring that tests which require adjustment of plant operating conditions adhere to plant operating, design and safety limits.

When a PEOA software failure was detected during testing, DHR was responsible for fixing the problem. The test director was notified when the problem was repaired so that testing could continue.

**PEOA TEST PROCEDURES**

Test procedure **PEOA-TP-001** describes the steps and evaluations necessary to validate that the appropriate data are obtained and displayed for use in the PEOA system, that the units of the data are correct, and that the range of data provided to train the system is appropriate.

The following is a listing of user interface display parameters analyzed:

- Process Variable: Description, Units, Value, Training Range (Min/Max), and Fixed values.
- Process Variable View Selection Options (Inputs and Outputs)

In general the TP-001 test procedure addresses the following specific capability requirements specified in the RTT (Table 4.2-1)

| RTT ITEM # |
|---|
| 2.1 |
| 5.1.3 |
| 5.2.1 |

Test procedure **PEOA-TP-002** describes the steps necessary to verify proper operation of the capabilities for the PEOA client software. It is intended to verify activation, control, and execution of such capabilities, and not necessarily to validate the correctness or accuracy of the results. This test procedure does not require manipulation of plant parameters.

The following is a listing of the user capabilities/functions that were analyzed during this test procedure:

- User Input
- Data Generation and Display
- Data Maintenance and Management
- Data Analysis

In general this test procedure addresses the following specific capability requirements specified in the RTT (Table 4.2-1):

| RTT ITEM # |
|---|
| 3.1.1 |
| 3.1.3 |
| 3.2.2 |
| 3.2.3 |
| 4.1.2 |
| 4.2.1 |
| 4.2.2 |
| 4.2.3 |
| 4.3.2 |
| 4.3.3 |
| 5.1.1 |
| 5.2.2 |
| 5.2.3 |
| 5.3.1 |
| 5.3.2 |
| 5.3.3 |
| 5.3.4 |
| 5.5 |

During this test procedure the model was not (consistently) using the correct bias values when performing a "What If' operation; because of the inconsistent nature of the error (it was only detectable when the biases changed radically due to swings in real-time plant data), a slight inaccuracy was introduced into the values given in the run file. Corrected values for the points verified are given in the table below. As might be expected, the greatest difference is visible in the projected costs; the difference in the predicted (“What If”-modeled) values was insignificant (< 0.001%), which constitutes an accurate verification of model results (which this test was intended to verify). This error was corrected and verified 1/31/95.

**Table 4.2-2**
**Deviations In PEOA-TP-002 Run Values**

| ***Data Point*** | ***Run*** | ***Value*** | ***New*** | ***% Diff*** | ***Target*** | ***New*** | ***% Diff*** | ***Cost*** | ***New*** | ***% Diff*** |
|---|---|---|---|---|---|---|---|---|---|---|
| $XsO_2$ | 0 | 3.62 | 3.62 | 0.000% | 3.00 | 3.00 | 0.000% | 5.24 | 5.24 | 0.00% |
|  | 1 | 3.00 | 3.00 | 0.000% | 3.00 | 3.00 | 0.000% | 0.00 | 0.00 | 0.00% |
|  | 2 | 3.60 | 3.60 | 0.000% | 3.02 | 3.00 | 0.662% | 4.60 | 5.80 | 26.09 % |
|  | 3 | 4.20 | 4.20 | 0.000% | 3.00 | 3.00 | 0.000% | 10.03 | 10.55 | 5.18% |
|  | 4 | 4.80 | 4.80 | 0.000% | 5.17 | 5.17 | 0.000% | -5.71 | -5.71 | .0.00% |
|  | 5 | 5.40 | 5.40 | 0.000% | 5.74 | 5.70 | 0.697% | -5.831 | -5.28 | -9.43% |
| Plant Earnings | 0 | 12816.80 | 12816.80 | 0.000% | 12998.84 | 12998.84 | 0.000% | 182.04 | 182.04 | 0.00% |
|  | 1 | 12820.54 | 12820.62 | 0.001% | 12999.68 | 12984.6 | 0.116% | 179.15 | 164.00 | 8.46% |
|  | 2 | 12817.41 | 12817.49 | 0.001% | 13000.58 | 12975.15 | 0.196% | 183.17 | 157.66 | 13.93 |

## Table 4.2-2
## Deviations In PEOA-TP-002 Run Values

| ***Data Point*** | ***Run*** | ***Value*** | ***New*** | ***% Diff*** | ***Target*** | ***New*** | ***% Diff*** | ***Cost*** | ***New*** | ***% Diff*** |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | % |
| | 3 | 12813.54 | 12813.62 | 0.001% | 12991.92 | 12991.92 | 0.000% | 178.39 | 178.30 | 0.05% |
| | 4 | 12808.79 | 12808.87 | 0.001% | 13013.44 | 12996.95 | 0.127% | 204.65 | 188.08 | 8.10% |
| | 5 | 12803.37 | 12803.37 | 0.000% | 13000.66 | 13010.57 | 0.076% | 197.30 | 237.12 | 4.98% |
| NetStnHtRt | 0 | 9351.29 | 9351.29 | 0.000% | 9740.60 | 9740.60 | 0.000% | NA | NA | NA |
| | 1 | 9280.30 | 9280.30 | 0.000% | 9587.90 | 9719.10 | 1.368% | NA | NA | NA |
| | 2 | 9347.04 | 9347.17 | 0.001% | 9717.25 | 9510.11 | 2.132% | NA | NA | NA |
| | 3 | 9419.43 | 9419.43 | 0.000% | 9728.77 | 9686.69 | 0.433% | NA | NA | NA |
| | 4 | 9500.04 | 9500.17 | 0.001% | 9695.49 | 9695.17 | 0.003% | NA | NA | NA |
| | 5 | 9592.23 | 9592.24 | 0.000% | 9832.51 | 9795.77 | 0.374% | NA | NA | NA |
| NOx | 0 | 0.38 | 0.38 | 0.000% | 0.42 | 0.42 | 0.000% | NA | NA | NA |
| | 1 | 0.38 | 0.38 | 0.000% | 0.35 | 0.41 | 17.143 % | NA | NA | NA |
| | 2 | 0.38 | 0.38 | 0.000% | 0.39 | 0.41 | 5.128% | NA | NA | NA |
| | 3 | 0.38 | 0.38 | 0.000% | 0.39 | 0.40 | 2.564% | NA | NA | NA |
| | 4 | 0.38 | 0.38 | 0.000% | 0.29 | 0.31 | 6.897% | NA | NA | NA |
| | 5 | 0.39 | 0.39 | 0.000% | 0.32 | 0.331 | 3.125% | NA | NA | NA |

The purpose of test procedure **PEOA-TP-003** is to verify the server capabilities/functions specified in the RTT. This test procedure does not require manipulation of plant parameters. The testing scope included testing the server's data acquisition capability of process variable values stored within the PI data base (both periodic and manual modes). In general this test procedure addresses the following specific capability requirements specified in the RTT (Table 4.2-1):

| RTT ITEM # |
|---|
| 4.1.1 |
| 4.3.3 |
| 5.2.1 |
| 5.4 |

Test procedure **PEOA-TP-004** was designed to evaluate the accuracy of the plant model and process calculations used to determine process inputs, outputs and cost/earnings values. Data analyzed during this test procedure were obtained from the PI data base via the PEOA server. Analysis of plant data used by PEOA can begin once the test data is captured and sent to the main display screen.

Process calculations that were evaluated are as follows:

- Model Input Calculations (MIC)
- Model Output Calculations (MOC)
- Process Cost Calculations (PCC)
- NN Model Accuracy

In general this test procedure addresses the following specific capability requirements specified in the RTT (Table 4.2-1):

| RTT ITEM # |
|---|
| 3.1.1 |
| 3.1.2 |
| 4.2.1 |
| 4.2.2 |
| 5.2.1 |
| 5.2.2 |

During the tests conducted on January 31st, February 1st and 2nd 1995, it was noted that the circulating water inlet temperature was approximately 40.5 $^{o}$F. This was below the minimum value of 45.03 $^{o}$F for which the neural network model was trained. This is due to the fact that the training data used was over a month old and the lake temperature had not dropped to the value experienced during the tests. Since circulating water inlet temperature is not an operator controllable parameter it was not possible to take additional data samples so that the temperature would be within the training range of the neural network model.

Minor differences between measured and calculated values are due to the use of PEOA's truncated values used in the manual calculations.

The purpose of test procedure **PEOA-TP-005** is to perform two separate optimization runs of PEOA and to have plant operations personnel implement the optimized plant settings (i.e. - target values) suggested by PEOA's optimizer. Various plant parameters are monitored before and after the implementation of target values designated by PEOA's optimizer. These parameters are then analyzed to determine PEOA's optimization viability. All operating parameters of the unit, other than those directly related to the test, must be kept as constant as possible during the test. Design and safety limits for operating parameters must be observed and adhered to during the test. Plant operators were responsible for maintaining plant safety during this test.

Testing was performed from the Milliken Station control room. Therefore, coordination between operations personnel and the test director was essential. Ideally, testing of the optimizer should be done after complete process variable data required by PEOA are available from the PI data base.

This test procedure was used to evaluate two independent runs of the optimizer. The first test was designed to determine if PEOA could increase gross and net generation output given that the plant is initially operating under normal operating conditions. The second test was designed to determine if PEOA could increase gross and net generation output given that the plant is initially operating in an other than normal operating condition. This was accomplished by having the shift supervisor instruct the operators to move process input parameter settings to values that they are not normally set to during normal plant operations.

In general this test procedure addresses the following specific capability requirements specified in the RTT (Table 4.2-1):

| RTT ITEM # |
|---|
| 3.1.3 |
| 3.2.2 |
| 4.2.3 |
| 5.3.2 |

During the testing it became apparent that additional operator controllable parameters should be added to the neural network model which should improve model accuracy. These parameters were designated to be added to PEOA before final turnover. The neural network input parameters designated for addition are: average auxiliary damper position and average concentric firing system damper position.

The generator's output was monitored throughout the testing in order to determine if improvements in boiler efficiency were apparent after the implementation of PEOA's optimized target values. Other process variables such as $NO_X$, LOI, throttle pressure, excess $O_2$ were also monitored to determine whether the implementation of PEOA's optimized target values would maintain them within their designated operating limits.

**TEST #1 OBSERVATIONS**

Before implementation of PEOA optimal target values the steady state conditions were observed as follows:

Average Gross Generation = 147.2 MW
Average Net Generation = 139.8 MW
$NO_X$ = 0.41 LB/MBTU
LOI = 3.95 % [4.4 %]

NOTE: LOI values displayed inside brackets are measured LOI values from samples taken at the time PEOA calculated them using the latest PI data base values. The following formula is used by PEOA to calculate LOI values. This formula was derived by NYSEG during testing at Milliken Unit 1 during the summer of 1994.

$$\text{LOI}(\%) = [8.1 - (1.08*\text{Excess } O_2(\%)) + (0.032*(\text{Net Boiler Load(MW)}-120)) - (0.062*(\text{Mill Classifier Speed(RPM)}-93)) + (0.155*\text{Bumer Tilt Position})]$$

After testing it was discovered that PEOA used net generation in place of net boiler load in the above equation. This accounts for the differences between the measured and calculated LOI values.

PEOA predicted that optimized $NO_X$ and LOI values are 0.35 LB/MBTU and 3.16% respectively.

After implementation of the optimal target values it was observed that both gross and net generation levels began a slow and steady increase over a period of 10 minutes, where they reached peak values of 149.1 MW and 141.4 MW respectively. It was then observed that both gross and net generation values began slowly decreasing in value for the next 30 minutes where their steady state values following the implementation of PEOA optimal target values were comparable although slightly lower then their pre-implementation values. Steady state $NO_x$ decreased from 0.41 to 0.39 LB/MBTU and measured LOI decreased from 4.4 to 4.1%. Stack flow decreased by approximately 10 kscfm while exit gas temperature remained constant.

## TEST #2 OBSERVATIONS

Before implementation of PEOA optimal target values the steady state conditions were observed as follows:

Average Gross Generation = 146.2 MW
Average Net Generation = 138.5 MW
$NO_x$ = 0.46 LB/MBTU
LOI = 3.41%

NOTE: Pre-optimization steady state $NO_x$ level was above the maximum value of 0.45 LB/MBTU.

PEOA predicted that optimized $NO_X$ and LOI values are 0.44 LB/MBTU and 4.0% respectively.

With process input parameters set in their other-than-normal operating setpoints it was observed that, after steady state operation was achieved, furnace to windbox DP set by the operators (4.0 in. WG) could not be obtained even though auxiliary air dampers and concentric firing system (CFS) dampers were automatically opened to 100%. The initial obtainable furnace to windbox pressure was recorded at 4.2 in. WG before optimization. Also noted was that gross and net generation output values settled at a lower steady state level than they were before process input parameters were changed to their other-than-normal settings.

After implementation of optimal target values it was observed that both gross and net generation levels began a slow and oscillating decrease over a period of 20 minutes, where they reached their lowest values of 144.2 MW and 136.55 MW respectively. Both gross and net generation values were then observed steadily increasing for approximately 30 minutes, where their new average steady state values were 147.2 MW and 139.67 MW respectively. Steady state $NO_X$ was reduced to 0.4 LB/MBTU, well below the maximum limit of 0.45 LB/MBTU. Steady state LOI increased slightly from 3.4% to 3.7%, which is below the maximum limit of 4.0%. There were no LOI samples taken during test #2.

## CONCLUSIONS

Both tests indicated that PEOA could maintain $NO_X$ and LOI levels within their designated limits. During Test #1 measured steady state $NO_X$ levels were optimized from 0.41 to 0.39 LB/MBTU, and calculated LOI levels were reduced from 3.95 to 3.48%. Even though PEOA's calculation of LOI was lower than the actual measured values (see LOI Calculations above in Test #1 Observations), PEOA did reduce actual measured LOI from 4.4 to 4.1%. PEOA's maximum limitation for LOI during the test was 4.0%.

During test #2 measured steady state $NO_X$ level before optimization was 0.46 LB/MBTU which is above the designated limit of 0.45 LB/MBTU. After implementation of PEOA's target values, steady state $NO_X$ level decreased to 0.4 LB/MBTU. There were no samples taken to measure LOI during the second test. However, calculated LOI levels were maintained below the designated limit of 4.0% during the entire test.

Although initial testing of PEOA's ability to increase plant efficiency proved inconclusive over the long term, there were some positive short term improvements observed. Test #2 showed an increase of approximately 1 MW in both gross and net generation outputs, about a 0.84% increase in energy sales income. Test #1 only showed improvement in both gross and net generation for approximately 20 minutes after which they settled to approximately their initial steady state levels.

Subsequent tests at Milliken Station are planned for the future. Future tests must be longer in duration so that average optimized gross and net generation values can be calculated. These optimized values will be compared to operator controlled gross and net generation values. These tests should be long enough to remove the transient effects due to changes in boiler cleanliness and soot-blowing operations. It is recommended that the test be 2 days in length, one day of plant parameters controlled by operations personnel, and one day where plant parameters are set to PEOA's optimal target values. Comparisons between the 2 days of operation should substantiate PEOA's viability in increasing overall plant efficiency. In order to improve test results the following problem areas should be addressed and efforts made to correct these problems where possible.

## PROBLEM AREAS

The following problem areas were identified during this testing period.

- Coal Mixture - The coal used during the testing period contained a mixture of 2 coals with different heating values. There may have been times when the percentages of these coals varied producing an increase or decrease in the average heating value of the coal entering the furnace.

- Cleanliness Factor Calculations. The calculations for air heaters A and B cleanliness factor (CF) were modified after neural network model training was complete. Newly calculated CF’s were used as inputs to the neural network model during testing. The neural network model was not trained with these calculations and thus the predictions made by the neural network model were somewhat compromised.

- Low Circulating Water Temperature. Circulating water Inlet temperature was 5 °F below the minimum values for which the neural network model was trained.

- Soot-Blowing. No soot-blowing was performed once testing began. Therefore, a small decrease was expected in generator output over time as boiler and tube surfaces became more and more fouled.

- Inaccuracies in Plant Measurements. The biggest concern is with the gravimetric coal flow meters. DHR resorted to an alternative method for calculating coal flow using: gross generation, gross unit heat rate, and coal heating value. Coal heating value was given a constant value of 12872 BTU/LB during neural network model training and during testing.

$$\text{Total Coal Flow(Ton/Hr)} = \frac{\text{Gross Unit Heat Rate (BTU/KHR X 1000(KW/MW) X Gross Gen (MW)}}{\text{Coal Heating Value (BTU/LB) X 2000(LB/Ton)}}$$

- LOI Calculations. PEOA used net generation in place of net boiler load in its formula to calculate LOI values.

### 4.2.2 REPORT OF PEOA TESTING CONDUCTED FEBRUARY 1998

The TOPAZ™ Optimizer Acceptance Test was conducted February 24 - 26, 1998 at Milliken Station. The test plan called for operation of the unit for 24 hours without the Optimizer followed by operation for 24 hours with the Optimizer. The unit was to be operated with the top three coal mills in operation and at high and moderate loads. The operating results would then be compared to quantify the economic benefits afforded by operation with the Optimizer.

The test did not go according to plan. During the second test period (operation with the Optimizer) it was discovered that the coal mill configuration was incorrect, invalidating the test data that had been collected to that time. In an attempt to salvage the remaining 12 hours of testing the system was operated with the Optimizer for the next 5 hours and without the Optimizer for the remaining 5 hours. During the testing the net unit load was held nearly constant at 110 MW. Additional testing was planned for the second quarter of 1998.

While the data collected during the abbreviated test periods are interesting, due to the shorter duration the test results are largely inconclusive. The overall heat rates attained during the tests periods were essentially equal (9800 Btu/kWh with the Optimizer and 9793 Btu/kWh without the Optimizer. There were some minor improvements gained while using the Optimizer (e.g. $NO_X$ was reduced by 0.05 lb/Mbtu); however, the benefits are too small to serve as the basis for any strong conclusions.

There were some significant differences between the two test periods including coal heating value (13,043.5 Btu/lb, as received, for the period the Optimizer was operating vs. 13,083.3 Btu/lb for the period without the Optimizer). Boiler efficiency was recalculated using the actual heating values (also using measured LOI) which resulted in improved efficiency numbers for both sessions. The heating value difference had the greatest impact on calculated coal flow since gross load was relatively steady for the remaining 10-12 hours (0.1 MW difference). Coal flow decreased during the session without the Optimizer since coal heating value increased.

Other notable differences included reduced FGD auxiliary load during operation without the Optimizer (by 385 kW) as well as a reduction of 606 kW in station service load. Theoretically, station service should have been the same for both sessions minus the effect of excess $O_2$ (i.e. fan power). To normalize the data between the two sessions, station service was adjusted to account for only the difference in $O_2$ based on previous $O_2$ vs. station service model curves. Heat rate, as well as overall plant earnings, was also recalculated.

Other differences between the two sessions included sootblowing and boiler fouling. Since each session was relatively short, sootblowing was not useful until late in the session without the Optimizer. The raw data indicate that waterwalls continued to foul (adding more heat to the convection pass) allowing for higher reheat and superheat temperatures during the latter session.

Another difference between the two sessions was a 0.55% difference in measured unburned carbon (LOI). While predicted LOI was used for on-line optimization, measured LOI values were used for analysis. While the LOI results for both sessions are quite good, errors in the LOI model may have a significant negative impact on future optimization results, since the error is often on the order of 25%. The error is not caused by inadequacies in the TOPAZ™ modeling technology, but rather by inadequacies in the available empirical data. This error greatly compromises the ability of the Optimizer to recommend good values for excess oxygen, which is also a critical parameter for $NO_X$ control.

## 4.3 VALIDATION OF BRIGHAM YOUNG UNIVERSITY 3D COMBUSTION CODE

The purpose of this program was to evaluate the accuracy of the Advanced Combustion Engineering Center (ACERC) PCGC-3 Combustion Code to predict key parameters such as $NO_X$ and unburnt carbon in the flyash exiting the boiler. Also included was the development of an empirical model to predict $NO_X$ and unburnt carbon for the Milliken CCTD.

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 $NO_X$ 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 $NO_X$ burners. The test data for the Milliken Station were obtained in July, 1995. A series of reports were delivered by ACERC that included the Field Measurement Report (NYSEG 1995) and the Comparison Report (NYSEG 1997). These reports are available from DOE upon request.

Spatially resolved, point-for-point comparisons are presented in the Comparison Report between Milliken Station predictions and measurements for gas composition ($CO_2$, CO, $SO_2$, $NO_X$, $O_2$), 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-$NO_X$ 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 $NO_X$ 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.

## 4.4 MILLIKEN LNCFS-3 EVALUATION

### 4.4.1 INTRODUCTION

The project's $NO_X$ emissions control strategy included combustion modifications to minimize $NO_X$ emissions and simultaneously optimize boiler thermal efficiency. NYSEG installed Low-$NO_X$ Concentric Firing System (LNCFS) burners. The burners are controlled by the boiler control system to optimize combustion efficiency while minimizing $NO_X$ emissions.

The objective of the LNCFS-3 evaluation program was to supplement and confirm earlier demonstrations of the LNCFS-3 low $NO_X$ 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.

### 4.4.2 LNCFS TEST PROGRAM

The effectiveness of Low-$NO_X$ Concentric Firing System Level 3 (LNCFS-3) burner retrofit to reduce $NO_X$ 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 $NO_X$ 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 DOE. A summary of the LNCFS demonstration program is provided below.

Unit 2 baseline test results were used to assess the $NO_X$ 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 160 MW gross (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 $NO_X$ 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-$NO_X$ burner retrofit was adopted. Unit 2 retrofit was scheduled approximately one year after that of Unit 1. A comparison of Units 1 and 2 $NO_X$ emissions was conducted using data from short-term tests (1-3 hours) and long-term measurements (60 days).

The Milliken pre-retrofit Unit 2 and post-retrofit Unit 1 are described in Table 4.4-1.

**TABLE 4.4-1 - MILLIKEN PRE-RETROFIT UNIT 2 AND POST-RETROFIT UNIT 1 DESCRIPTION**

| | | Pre-Retrofit Unit 2 | Post-Retrofit Unit 1 |
|---|---|---|---|
| Mills- Type | - Type | CE RB6134 | Riley Stoker MPS150 |
| | - Quantity | 4 | 4 |
| | - Performance | 33,500 lb/h at 57 HGI Coal | 36,800 lb/h at 57 HGI Coal |
| Classifiers | - Type | Static | Dynamic, Riley Stoker SLS |
| | - Quantity | 4 | 4 |
| | - Performance | 70% -200 Mesh | 93% -200 Mesh |
| PA Fans | - Type | None, Exhausters With Mills | Centrifugal Design, Buffalo Forge |
| Feeders | - Type | Volumetric, Variable Stroke Drive | Gravimetric, Stock Equipment |
| | - Quantity | 4 | 4 |
| | - Performance | Normal Feed at High Load | 20 tons/h |
| Burners | - Type | CE TV Type, Vertical Adjustable | JABB CE LNCFS-3 |

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 $NO_X$ 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 $NO_X$ 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 $NO_X$ emissions.

At full boiler load (145-150 MW) and 3.0%-3.5% economizer $O_2$, the LNCFS-3 burner lowered $NO_X$ 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 $O_2$ the LNCFS-3 burner lowered $NO_X$ 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 $O_2$ 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 $O_2$, coal air flow, burner tilt, and reduced load mill patterns on $NO_X$ emissions and LOI. The following conclusions were reached:

- Both $NO_x$ and LOI results showed good reproducibility. Uncertainties at 95% confidence were ± 0.016 lb $NO_x$/MM Btu and ± 0.30% LOI. $NO_2$ was not measured, and reported $NO_X$ measurements were the sum of both NO and $NO_2$.

- Changing fuel air damper position had a significant effect on LOI and a minor effect on $NO_X$ 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 $NO_X$ emissions, but not LOI. Changing burner tilt from $\pm 15^o$ to $0^o$ increased $NO_X$ emissions by 0.04 lb/MM Btu.

- At reduced boiler loads (110 MW and lower), taking the top burner elevation out of service reduced $NO_X$ emissions, but made it difficult to maintain steam temperatures.

- Higher excess $O_2$ levels (measured at economizer outlet) increased $NO_X$ emissions and reduced LOI. The results showed that the impact of excess air on $NO_X$ emissions was reduced at lower boiler loads.

- Higher boiler loads increased $NO_X$ emissions and reduced LOI at the same excess $O_2$ level.

- Lower $NO_X$ emissions corresponded to higher LOI. Predictive correlations for $NO_X$ emissions and LOI were derived:

  $$1b\ NO_x\ /MM\ Btu = 0.34 - 0.036*02 + 0.0009*MW*O_2 - 0.00017*(TILT)^2 \quad r^2 = 91\%$$

  $$\%\ LOI = -1.2 + 9.4/O_2 + 0.25*AIR - 0.024*(MW-140) \qquad r^2 = 84\%$$

  where
  $O_2$ is excess $O_2$ 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 $NO_X$ 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 $O_2$, 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 $NO_X$ emissions and LOI. The following conclusions were reached:

- The post-retrofit tests had a greater level of uncertainty in $NO_X$ emissions and about the same level of uncertainty in LOI, compared to the baseline tests, Uncertainties at 95% confidence were ± 0.027 lb $NO_X$ /MM Btu and ± 0.35% LOI.

- Gas stratification across the two ducts at the economizer outlet was minor.

- $NO_2$ 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 ($0^o$) was estimated to reduce $NO_X$ 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 $NO_X$ emissions or LOI. SOFA yaw changes (relative to the fuel firing angle) did not significantly change $NO_X$ 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 $NO_X$ emissions and increased LOI. Changes in SOFA damper position had a greater effect on $NO_X$ 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 $NO_X$ emissions and LOI, but the effect was greater on $NO_X$ emissions.

- Higher excess $O_2$ increased $NO_X$ emissions and reduced LOI.

- In general, higher boiler loads increased both $NO_X$ emissions and LOI.

- Higher mill classifier speeds reduced both $NO_X$ emissions and LOI, but the effect on LOI was more dramatic.

- The post-retrofit relationship between $NO_X$ and LOI was more complex than the pre-retrofit relationship because of greater sensitivity of the low $NO_X$ 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 $NO_X$ emissions.

- Predictive correlations for $NO_x$ emissions and LOI were derived:

  $$\text{lb } NO_X \text{ /MM Btu} = 0.12 + 0.08{*}O_2 + 0.00003{*}(MW-120)^2 - (RPM-93) + 0.007{*}TILT \qquad r^2 = 84\%$$

  $$\% \text{ LOI} = 8.1 - 1.08{*}O_2 + 0.032{*}(MW-120) - (RPM-93) + 0.155{*}TILT \qquad r^2 = 69\%$$

  where
  $O_2$ is excess $O_2$ 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 $NO_X$ emissions could potentially be reduced to about 0.35 lb/MM Btu at full boiler load, while maintaining salable fly ash.

- The low $NO_X$ burner retrofit reduced $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ and CO emissions, fly ash LOI and boiler efficiency.

The achievable annual $NO_X$ emissions were estimated using long-term (60-70 days) CEM measurements. The achievable annual $NO_X$ 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 $NO_X$ emissions for Unit 2 baseline were 0.614 lb/MM Btu, with a 95% confidence level of ± 0.023 lb/MM Btu.

- The achievable annual $NO_X$ emissions for Unit 1 LNCFS-3 were 0.390 lb/MM Btu, with a 95% confidence level of ± 0.003 lb/MM Btu. That corresponded to 134 MW boiler load and 3.72% $O_2$ at the economizer outlet. The LNCFS-3 burner system achieved 36% $NO_x$ reduction. However, direct comparison of baseline and post-retrofit $NO_X$ emissions can be misleading, since the corresponding economizer $O_2$ 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 $NO_X$ 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 $O_2$ and boiler load. The test parameters for Unit 1 LNCFS-3 were economizer $O_2$, coal fineness and boiler load. The following conclusions were reached:

- For Unit 2 baseline, satisfactory predictions were obtained for both $NO_X$ 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 $NO_X$ /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 $NO_X$ emissions at full boiler load (145-150 MW).However, predictions for $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ emissions, boiler efficiency, fly ash LOI and CO emissions. Specifically:

- At full boiler load (145-150 MW) and 3.0%-3.5% economizer $O_2$, the LNCFS-3 system lowered $NO_X$ 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 $O_2$, the LNCFS-3 system lowered $NO_X$ 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 $O_2$ 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.

## 4.5 MILLIKEN SELECTIVE NON-CATALYTIC REDUCTION 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 $NO_X$ emissions beyond that achievable by combustion modifications alone. Nalco'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 $NO_X$ emissions by more that 30% in addition to the reductions achieved by combustion modifications. Project goals included:

- Demonstration of additional $NO_X$ reductions beyond the reductions achieved by combustion modifications;
- Minimal ammonia ($NH_3$) slip, with a goal of $\leq 2$ 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, $CaCl_2$.

The original NOxOUT® demonstration program included supplemental process monitoring to (1) monitor operating conditions for process control and (2) evaluate the effect of operating conditions on $NO_X$ reduction efficiency, by-product (gypsum, calcium chloride, bottom ash and fly ash) quality, load following capability, annual operating and maintenance costs and ammonia slip. 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.

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.

### 4.5.1 NOxOUT® PROCESS DESCRIPTION

The NOxOUT® SNCR system removes $NO_X$ by injecting urea ($NH_2CONH_2$) and proprietary additives into the boiler post-combustion zone. Urea converts $NO_X$ into carbon dioxide, nitrogen and water via the following reactions:

$$2NO + NH_2CONH_2 + 1/2\ O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

$$2NO_2 + 2NH_2CONH_2 + O_2 \rightarrow 3N_2 + 2CO_2 + 4H_2O$$

These reactions take place in the 1600 °F to 2100 °F temperature range. Below 1600 °F, ammonia ($NH_3$) slip increases. At temperatures significantly above 2100 °F, $NO_X$ emission levels actually increase. The NOxOUT® process uses patented chemical enhancers and mechanical modifications to widen this temperature range and to control the formation of ammonia.

The urea-based reagent is stored on site in atmospheric-pressure tanks; a scrubbing system on the tank vents is not required. A metering pump delivers the reagent from the storage tank to an in-line mixer which dilutes the reagent with water. The reagent/water ratio is about 1:4. The diluted liquid is pumped to two-fluid atomizers where the solution is atomized using compressed air. The atomizing air:solution ratio is typically 0.1 to 0.25 by weight. The air pressure depends on the required mixing penetration depth into the boiler, but in most cases is between 50 and 60 psig. The injector location in the boiler is determined after performing temperature profile measurements. Three injector levels are installed. At least two are needed to be able to handle load changes. The third provides greater flexibility of operation and additional parameters for testing. The number of injectors per level is specified by Nalco Fuel Technologies following computational modeling of boiler geometry and heat transfer, flue gas flow dynamics, chemical kinetics and spray nozzle penetration. The process uses proprietary injection nozzles that provide a very narrow droplet size distribution. Control hardware and software are specified and designed to enable the NOxOUT® process to compensate for load changes. Process control is performed automatically based on data from continuous on-line process monitors.

## 4.6 MILLIKEN ESP UPGRADE EVALUATION

### 4.6.1 INTRODUCTION

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 $^{o}$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 $NO_x$ 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 150 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 DOE 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 4.6-1
### PRECIPITATOR CHARACTERISTICS
### ORIGINAL VS. MODIFIED ESP

| | Lower ESP | Upper ESP | New ESP |
|---|---|---|---|
| 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, $ft^2$/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 $ft^2$ 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 ($SO_2$)
- Sulfuric Acid Mist ($SO_3$)
- Particle Size Distribution
- Flue Gas Composition ($O_2$, $CO_2$, $N_2$, and $H_2O$)
- 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$^{TM}$.

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.

### 4.6.2 SAMPLING LOCATIONS

**ESP Inlet -** The ESP inlet sampling point was located immediately upstream of the ESP. Each duct was fitted with twelve 6-in sampling ports. A sampling scheme using every other sampling port was used for the PM sampling. Sampling was conducted at port depths of 7-in, 21-in and 35-in. This plan resulted in a total of six ports and 18 sampling points for each duct. PM sampling was conducted for 6 minutes at each point which resulted in a total sampling time of 108 minutes.

Particle size measurements were conducted at the mid-point in three ports for each duct. The ports were selected based on the velocity profile obtained during the PM sampling.

$SO_3$ sampling was conducted through ports C and 1. Resistivity measurements were taken at every other port.

**ESP Outlet -** Sampling was conducted in the two outlet ducts located immediately downstream of the ESP. Each duct was fitted with twelve 6-in sampling ports and the sampling scheme was identical to the ESP inlet sampling. PM sampling was conducted for 8 minutes at each point which resulted in a total sampling time of 144 minutes. Longer sampling times were used at this location due to the low particulate loadings.

Particle size sampling was conducted at the mid-point in two different ports for each duct. These ports were selected based on the velocity profile obtained from the PM sampling data.

$SO_3$ sampling was conducted through ports C and 1. Resistivity measurements were taken at every other port.

**As-Fired Coal Samples -** Coal samples were taken from the individual gravimetric feeders located above the coal mills. The samples were obtained using the automatic samplers that were installed on each feeder. The samples were coordinated with the emission measurements. Sample size and increments were taken in accordance with ASTM procedures. At the completion of the test program, each gross coal sample was riffled down to fit into a 5-gallon bucket. The samples were then transported back to the CONSOL lab for final sample preparation and subsequent analysis.

### 4.6.3 EXPERIMENTAL

The emissions sampling was conducted using EPA reference techniques, where applicable. In cases where no suitable reference method existed, sampling was conducted using EPA-endorsed methodologies or other published, well-documented procedures. A summary of the sampling procedures used in this test program is provided below.

**Selection of Sampling Points -** The sampling points at both locations were selected as described in EPA Method 1. Neither location met the standard EPA requirement for the minimum number of sampling points and additional sampling points were used to help offset any potential location biases.

**Volumetric Flow Rate -** Individual point velocities and duct volumetric flow rates were determined in conjunction with the PM sampling using the procedure outlined in EPA Method 2. The particulate sampling probes were equipped with type “S” pitot assemblies complete with thermocouples which were calibrated prior to the test program.

**Gas Composition ($O_2$, $CO_2$ and $N_2$) -** Flue gas compositions at both locations were determined using a Teledyne Model Max 5 combustion gas analyzer. This instrument uses an electrochemical sensor to determine oxygen and calculates the $CO_2$ concentration based on fuel chemistry. Nitrogen is determined by difference. The $O_2$ and $CO_2$ concentrations determined by this instrument were confirmed by Orsat analysis. The dry molecular weights of the flue gas samples were calculated from these data as outlined in EPA Method 3.

**Flue Gas Moisture Content -** Flue gas moisture was determined by measuring the condensate collected in the impinger assemblies for each of the PM samples. The impinger recovery procedure and calculations are outlined in EPA Method 4, Method 5 and Method 17.

**Particulate Matter Concentrations -** The PM sampling was conducted at both the ESP inlet and outlet as outlined in EPA Method 17. This method specifies the use of an in-stack filter at the front end of the sampling probe. Particulate matter is defined as any material that is collected on the filter at the duct temperature and pressure. Both the ESP inlet and outlet locations had a nominal average temperature of ~290$^{o}$ F and an absolute pressure of ~28.5” Hg.

A stainless steel filter canister fitted with a high efficiency ceramic filter was used at the inlet locations. This assembly can hold up to 50 g of particulate and is particularly well suited for high particulate loading applications.

Obstructive support beams near the port locations at the ESP outlet location made Method 5 sampling difficult. Because of this, an in-stack filter system was used.

Originally, a flat-pack filter was tried. However, due to filter recovery problems, this was replaced with a 63 mm in-stack stainless steel filter holder. This sampling component allowed for the use of 63 mm quartz-fiber filters. These filters have greater weight stability and are more easily recovered from the filter holder after sampling. These attributes result in more accurate mass measurements. As with the inlet sampling, the filter temperature is maintained at the flue gas temperature. Particulate matter is defined as any material that is collected on the sampling media at duct conditions of ~290 $^oF$ and an absolute pressure of ~28.5-in Hg.

**$SO_2$ Emissions -** $SO_2$ concentrations were measured by replacing the water solution in the PM sampling impingers with a 3% hydrogen peroxide solution. After sampling, the impinger contents were analyzed for $SO_2$ as described in EPA Method 6. This technique is a $BaCl_2$ titration to a thorin end point. Additional $SO_2$ measurements were obtained with the acid condensation sampling trains using a similar recovery and analytical procedure.

**Particle Size Sampling ESP Inlet -** Particle size sampling was conducted at the ESP inlet using an Andersen 5-stage cyclone sampler. This sampler is designed to operate inside of the duct (in situ) and provides aerodynamic particle size data. The sampling protocol was conducted as outlined in the instruction manual and followed published procedures prepared by Southern Research Institute for the California Air Resource Board.

**Particle Size Sampling ESP Outlet -** Particle size sampling was conducted at the ESP outlet using an Andersen 7-stage impactor sampler. This sampler is designed to operate in situ and provides aerodynamic particle size data. The sampling protocol was conducted as outlined in the instruction manual and followed published procedures prepared by Southern Research Institute for the California Air Resource Board. The impactor was fitted with a right-angle flow adapter which eliminated the need for the goose-neck inlet nozzle. The right-angle flow adapter produces a more valid size distribution.

**$SO_3$ Measurements -** $SO_3$ measurements were made using a CONSOL R&D modified EPA “Miniature Acid Condensation System “ (MACS). In this sampling train, the flue gas is pulled through a heated quartz probe (500 $^oF$) fitted with a quartz wool filter plug into a condenser packed with glass wool. The condenser temperature is maintained at ~140 $^oF$ which allows for the selective condensation of $SO_3$ (as sulfuric acid mist). The gas then exits the condenser and is pulled through hydrogen peroxide-filled impingers which oxidize the $SO_2$ to sulfate. After sampling, the quartz plug, sampling probe, condenser and impingers are separately recovered and analyzed for sulfate using the $BaCl_2$ titration discussed in EPA Method 6. Additional $SO_2$ measurements are also obtained with this sampling method.

**Ash Resistivity Measurements -** Resistivity measurements were made using a point-to-plane fly ash resistivity probe designed and fabricated by engineers from Southern Companies. With this probe, the voltage drop across an ash layer is determined by taking the difference between the “clean plate” and “ dirty plate” V-I curves and using the corresponding measured current. Measurements were also calculated using the “spark method”. These methods are documented in the instructions supplied with the sampling probe.

### 4.6.4 UNIT 2 OPERATING CONDITIONS

A variety of plant operating variables were monitored to assure steady-state, base load operations for all test periods. These data were recorded by the existing plant data system and transferred to CONSOL personnel. A summary of major plant parameters is provided below, in table 4.6-2.

**TABLE 4.6-2**
**PLANT OPERATING PARAMETERS**
**(hourly averages for each day of testing)**

| Parameter | 10/17/95 | 10/18/95 | 10/19/95 | 10/20/95 | Avg |
|---|---|---|---|---|---|
| Gas Flow, KACFM | 493 | 500 | 498 | 501 | 498 |
| PRSD | 0.5% | 0.7% | 0.8% | 0.5% | 0.7% |
| Inlet Temp $^{o}$F | 292 | 301 | 298 | 302 | 298 |
| PRSD | 1.6% | 1.4% | 1.2% | 0.8% | 1.5% |
| Coal Feed, tph | 54.60 | 53.99 | 53.00 | 54.00 | 54.15 |
| PRSD | 0.0% | 0.0% | 0.0% | 0.0% | .6% |
| Net MW | 148.5 | 148.4 | 147.7 | 147.7 | 148.1 |
| PRSD | 0.3% | 0.2% | 0.5% | 0.2% | 0.3% |
| Economizer %$O_2$ | 4.00 | 4.10 | 4.10 | 4.01 | 4.05 |
| PRSD | 0.8% | 0.2% | 0.2% | 3.4% | 1.4% |
| % Opacity | 2.80 | 2.37 | 3.37 | 1.5 | 2.51 |
| PRSD | 36% | 23% | 23% | 22% | 31% |

These data show very low daily variation. Station load, coal feed rate, gas flow rate and % $O_2$ at the economizer outlet showed daily variabilities of less than 1% (10/20/95 $O_2$ showed a PRSD of ~3%), verifying uniform daily test conditions. The weekly variations for these parameters were also very low, which verify steady-state conditions for each test day.

### 4.6.5 AS-FIRED COAL ANALYSIS

Coal samples were obtained for each test day and coincided with the daily sampling activities. The proximate, ultimate and major elemental analyses completed on these samples are shown in table 4.6-3. Key coal quality parameters are summarized in table 4.6-4.

## TABLE 4.6-3
## ANALYSIS OF MILLIKEN BOILER FEED COAL SAMPLES
### (As-fired Basis)

| Coal ID | 1 | 2 | 3 | 4 | AVG | SDEV | PRSD |
|---|---|---|---|---|---|---|---|
| Volatile Matter | 36.24 | 36.69 | 36.04 | 36.11 | 36.27 | 0.291 | 0.8% |
| Ash | 6.56 | 6.61 | 6.77 | 6.79 | 6.69 | 0.11 | 1.7% |
| Carbon | 73.53 | 73.51 | 73.83 | 73.67 | 73.68 | 0.12 | 0.2% |
| Hydrogen | 4.79 | 4.84 | 4.72 | 4.75 | 4.77 | 0.05 | 1.1% |
| Nitrogen | 1.46 | 1.49 | 1.48 | 1.47 | 1.47 | 0.01 | 0.8% |
| Sulfur | 1.72 | 1.76 | 1.74 | 1.76 | 1.75 | 0.02 | 1.1% |
| Oxygen | 4.99 | 5.32 |  | 5.33 | 5.18 | 0.17 | 3.3% |
| Total Moisture | 6.96 | 6.27 | 6.39 | 6.23 | 6.46 | 0.34 |  |
| Btu/lb | 13,035 | 13,141 | 13,096 | 13,112 | 13,096 | 45 | 0.3% |
| $F_d$ Factor, $O_2$[1] | 9993 | 9928 | 9952 | 9918 | 9948 | 34 | 0.3% |
| F Factor, $CO_2$ | 1811 | 1800 | 1810 | 1803 | 1806 | 5 | 0.3% |

### Dry Basis

| Coal ID | 1 | 2 | 3 | 4 | AVG | SDEV | PRSD |
|---|---|---|---|---|---|---|---|
| Volatile Matter | 38.95 | 39.15 | 38.50 | 38.51 | 38.78 | 0.32 | 0.8% |
| Ash | 7.05 | 7.06 | 7.23 | 7.25 | 7.15 | 0.11 | 1.5% |
| Carbon | 79.02 | 78.64 | 78.87 | 78.56 | 78.77 | 0.21 | 0.3% |
| Hydrogen | 5.14 | 5.16 | 5.04 | 5.06 | 5.10 | 0.06 | 1.2% |
| Nitrogen | 1.57 | 1.59 | 1.58 | 1.57. | 1.57 | 0.01 | 0.6% |
| Sulfur | 1.85 | 1.88 | 1.86 | 1.88 | 1.87 | 0.01 | 0.8% |
| Oxygen | 5.36 | 5.68 | 5.43 | 5.68 | 5.54 | 0.17 | 3.0% |
| Btu/lb | 14,010 | 14,020 | 13,990 | 13,984 | 14,001 | 17 | 0.1% |
| $F_d$ Factor, $O_2$ | 9881 | 9827 | 9849 | 9819 | 9844 | 28 | 0.3% |
| F Factor, $CO_2$[2] | 1811 | 1800 | 1810 | 1803 | 1806 | 5 | 0.3% |

**Analysis of Major Ash Elements, % of Dry Ash**

| Coal ID | 1 | 2 | 3 | 4 | AVG | SDEV | PRSD |
|---|---|---|---|---|---|---|---|
| $SiO_2$ | 48.63 | 47.23 | 46.42 | 47.47 | 47.44 | 0.91 | 1.9% |
| $Al_2O_3$ | 24.05 | 23.37 | 23.20 | 23.26 | 23.47 | 0.39 | 1.7% |
| $TiO_2$ | 0.98 | 0.98 | 0.94 | 0.95 | 0.96 | 0.02 | 2.1% |
| $FeO_3$ | 17.83 | 19.21 | 18.72 | 17.26 | 18.26 | 0.87 | 4.8% |
| CaO | 2.72 | 2.78 | 2.85 | 2.98 | 2.83 | 0.11 | 3.9% |
| MgO | 0.78 | 0.75 | 0.77 | 0.82 | 0.78 | 0.03 | 3.8% |
| $Na_2O$ | 0.65 | 0.61 | 0.64 | 0.69 | 0.65 | 0.03 | 5.1% |
| $K_2O$ | 1.77 | 1.67 | 1.69 | 1.79 | 1.73 | 0.06 | 3.4% |
| $P_2O_5$ | 0.50 | 0.50 | 0.50 | 0.49 | 0.50 | 0.00 | 1.0% |
| $LiO_2$ | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.00 | 0.0% |
| $SO_3$ | 2.28 | 2.27 | 2.55 | 2.82 | 2.48 | 0.26 | 10.5% |
| Undermined | -0.21 | 0.61 | 1.70 | 1.45 | 0.89 | 0.87 | 97.7% |

1 & 2 - F Factor is in units of dscf of flue gas produced per MM Btu heat input using $O_2$ or $CO_2$

**TABLE 4.6-4**
**SUMMARY OF DAILY COAL SAMPLE ANALYSES**
**(results on dry basis)**

| Parameter | Average | SDEV | PRSD |
|---|---|---|---|
| Total Moisture, % | 6.5 | 0.3 | 5.2 |
| Carbon, % | 78.77 | 0.21 | 0.3 |
| Sulfur, % | 1.87 | 0.01 | 0.8 |
| Ash, % | 7.15 | 0.11 | 1.5 |
| Volatile Matter, % | 38.78 | 0.32 | 0.8 |
| Heating Value, Btu/lb | 14,001 | 17 | 0.1 |
| F-Factor, dscf flue gas per MMBtu heat input | 9,844 | 28 | 0.3 |

These data show a very consistent coal feed for the four test days, making day-to-day comparisons meaningful.

### 4.6.6 FLUE GAS FLOW DISTRIBUTION

The flue gas flow distribution between the north and south precipitators and a comparison of flows at the inlet and outlet sampling locations, along with flue gas temperatures and velocities are shown in table 4.6-5.

**TABLE 4.6-5**
**FLUE GAS FLOW DISTRIBUTION**

| Avg Measurements for All Test Periods | North Inlet | North Outlet | South Inlet | South Outlet |
|---|---|---|---|---|
| Flue Gas Temp, $^oF$ | 292 | 294 | 296 | 289 |
| Flue Gas Velocity, fpm | 37.8 | 37.2 | 38.5 | 37.5 |
| Volumetric Flow, acfm<br>PRSD | 270,000<br>3.7% | 265,500<br>2.9% | 275,000<br>3.1% | 267,700<br>2.1% |
| Volumetric Flow, dscfm<br>PRSD | 167,500<br>2.4% | 165,700<br>1.2% | 167,800<br>2.3% | 166,700<br>1.3% |

The flue gas volumetric flow rates to each precipitator show an even split between the north and south precipitators. The percent difference between the inlet and outlet volumetric flow rates (dscfm) was ~1% for both the north and south sides. These differences are well within the uncertainty of the pitot tubes used in the measurements and are not a cause for concern. The reproducibility of the flow measurements indicate steady-state boiler operation for each of the test periods.

### 4.6.7 PERFORMANCE TEST RESULTS

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:

$$\text{Penetration} = 100 - \text{Percent Removal}$$

or

$$\text{Penetration} = 100 - \left[\frac{\text{Concentration of Solids in Outlet}}{\text{Concentration of Solids in Inlet}}\right] \bullet 100$$

Penetrations for the <10 µm and <2.5 µm 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. Thus,

$$\text{Penetration}, < 10\text{mmFrac.} = 100 - \left[\frac{(\text{OutletSize}, < 10\text{mmFrac.})\bullet(\text{Conc.ofSolidsinOutlet})}{(\text{InletSize}, < 10\text{mmFrac.})\bullet(\text{Conc.ofSolidsinInlet})}\right] \bullet 100$$

The equation for the <2.5 µm fraction is similar.

The coal and fly ash properties did not change appreciably between the baseline test and the performance test on the modified ESP, as shown in tables 4.6-6 and 4.6-7. 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. (See tables 4.6-8 and 4.6-9.) 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.

## TABLE 4.6-6
## AVERAGE COAL ANALYSES
## COAL TYPE: BITUMINOUS
## (Average of the analyses of the daily cumulative samples)

| | April 1994 | October 1995 |
|---|---|---|
| Coal Analysis, wt% dry basis | | |
| Moisture | | 6.46 |
| Carbon | 78.01 | 78.77 |
| Hydrogen | 5.25 | 5.10 |
| Nitrogen | 1.51 | 1.57 |
| Oxygen (diff) | 6.35 | 5.54 |
| Sulfur | 1.79 | 1.87 |
| Ash | 7.10 | 7.15 |
| HHV, Btu/lb | 13,950 | 14,000 |
| | | |
| Ash Analysis, wt% ash | | |
| $Li_2O$ | | 0.02 |
| $Na_2O$ | | 0.656 |
| $K_2O$ | | 1.73 |
| MgO | | 0.78 |
| CaO | | 2.83 |
| $Fe_2O_3$ | | 18.26 |
| $Al_2O_3$ | | 23.47 |
| $SO_2$ | | 47.44 |
| $TiO_2$ | | 0.96 |
| $P_2O_5$ | | 0.50 |
| $SO_3$ | | 2.48 |
| Unknown | | 0.87 |

## TABLE 4.6-7
## FLY ASH ANALYSES
## (Average of the analyses of the test samples)

| Ash analysis, wt%, as received | April 1994 | October 1995 |
|---|---|---|
| Carbon | 4.04 | 2.4 |
| Nitrogen | 0.03 | |
| Sulfur | 0.35 | 0.45 |
| Moisture | | 0.46 |
| Ash | | 96.87 |

## TABLE 4.6-8
## APRIL 1994 FLY ASH RESISTIVITY

| Date | Duct/Port | Temp. °F | Resistivity, Ohms |
|---|---|---|---|
| 4/17/94 | A/8 | 283 | $6.51 \times 10^{10}$ |
| 4/18/94 | A/2 | 251 | $4.09 \times 10^{10}$ |
| 4/18/94 | A/2 | 252 | $7.67 \times 10^{10}$ |
| 4/18/94 | A/5 | 269 | $4.49 \times 10^{10}$ |
| 4/18/94 | B/2 | 272 | $3.09 \times 10^{10}$ |
| 4/18/94 | B/5 | 272 | $8.90 \times 10^{10}$ |
| 4/18/94 | B/9 | 230 | $5.69 \times 10^{10}$ |

## TABLE 4.6-9
## OCTOBER 1995 FLY ASH RESISTIVITY

| | Samples Collected From North Side | | | | Samples Collected From South Side | | | |
|---|---|---|---|---|---|---|---|---|
| | October 17 | | October 18 | | October 19 | | October 20 | |
| Port | Temp °F | Resistivity, Ohm | Temp °F | Resistivity, Ohm | Temp °F | Resistivity, Ohm | Temp °F | Resistivity, Ohm |
| B | 297 | $4.49 \times 10^{10}$ | 302 | $1.39 \times 10^{10}$ | 289 | $2.02 \times 10^{10}$ | 295 | $2.20 \times 10^{10}$ |
| D | 291 | $3.90 \times 10^{10}$ | 293 | $4.74 \times 10^{10}$ | 299 | $2.93 \times 10^{10}$ | 302 | $4.67 \times 10^{10}$ |
| F | 288 | $2.09 \times 10^{10}$ | 297 | $4.23 \times 10^{10}$ | 293 | $3.87 \times 10^{10}$ | 292 | $1.98 \times 10^{10}$ |
| H | 299 | $2.68 \times 10^{10}$ | 305 | $3.86 \times 10^{10}$ | 277 | $2.07 \times 10^{10}$ | 280 | $2.29 \times 10^{10}$ |
| J | 289 | $3.02 \times 10^{10}$ | 297 | $3.30 \times 10^{10}$ | 295 | $3.43 \times 10^{10}$ | 300 | $2.25 \times 10^{10}$ |
| L | 278 | $1.72 \times 10^{10}$ | 278 | $1.37 \times 10^{10}$ | 304 | $3.69 \times 10^{10}$ | 300 | $2.58 \times 10^{10}$ |

Results of the performance showed that the overall removal improves 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 4.6-10 and 4.6-11. 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 4.6-10
### APRIL 1994 ESP TR-SET PRIMARY SIDE CONDITIONS
### MILLIKEN UNIT 2 ESP BASELINE TESTS

| | 17-Apr-94 | | 18-Apr-94 | | 19-apr-94 | |
|---|---|---|---|---|---|---|
| TR-Set Designation | 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 4.6-11
### OCTOBER 1995 ESP TR-SET PRIMARY SIDE CONDITIONS
### MILLIKEN UNIT 2 MODIFIED ESP TESTS
### (averages of readings recorded during the performance tests)

| | 17-Oct-95 | | 18-Oct-95 | | 19-Oct-95 | | 20-Oct-95 | |
|---|---|---|---|---|---|---|---|---|
| TR-Set Designation | 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 |

## 4.6.8 CONCLUSIONS

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.

## 4.7 EVALUATION OF ESPert™ ESP MODEL

### 4.7.1 INTRODUCTION

The performance of an electrostatic precipitator (ESP) model (ESPert™) was evaluated for a 160 $MW_e$ pulverized coal-fired power plant firing a medium sulfur, bituminous coal. The ESP was recently modified to improve its effectiveness. New internals, computer controlled transformer-rectifier sets and a third field were installed. The plates have a 16-inch plate spacing. The ESPert™ model, developed for EPRI, consistently under-predicted the effectiveness of the ESP at full load. The results of this evaluation program can be found in detail in the report entitled “Milliken Clean Coal Technology Demonstration Project, Comparison of ESPert™ Model Predictions with Unit 2 Electrostatic Precipitator Performance” prepared by CONSOL and NYSEG, dated November 1997. The full report is available from DOE upon request. What follows is a summary of that report.

### 4.7.2 SUMMARY

ESPert™ ESP model was evaluated by comparing the predicted performance with actual ESP performance measured at Milliken Station Unit 2 of the New York State Electric & Gas Corporation (NYSEG). Milliken Station is an electric utility station with two 160 $MW_{e,}$ pulverized coal-fired steam generators. As part of the modifications required for installation of a flue gas desulfurization system, the Unit 2 ESP was modified. New internals were installed with a wide, 16-inch plate spacing. Computer controlled transformer-rectifier (TR) sets were added. This evaluation shows that the ESP model significantly under-predicts 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 confirm that the operating conditions for this ESP are outside the range expected by ESPert™. Additional tests with other coals should be undertaken to define the effects of wide plate spacing.

### 4.7.3 DISCUSSION

#### BACKGROUND

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 physical characteristics of the old and new ESP’s are shown in the following table.

## TABLE 4.7-1
## PRECIPITATOR CHARACTERISTICS

| | Original ESP[1] | | |
|---|---|---|---|
| | Lower ESP | Upper ESP | New ESP |
| Date Built | 1955-58 | 1971-74 | 1993 |
| Plate Spacing, inches | 8 ¾ | 9 | 16 |
| Plate Height, feet | 20 | 30 | 30 |
| Fields | 2 | 2 | 3 |
| Field Depth, feet, each | 9 | 9 | 9 |
| Gas Velocity, fps | 5.7 | 3.4 | 3.7 |
| SCA, $ft^2$/1,000 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 $ft^2$ 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.

Currently the Milliken Unit 2 ESP 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 dividing upstream of the air heater and rejoining at the scrubber. Each side has an additional divider 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.

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. The results of these tests are compared with the performance predictions made by ESPert™, an ESP model developed by Peter Gelfand of P. Gelfand Associates under the auspices of EPRI. 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.

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. The design parameters of Unit 2 were adjusted accordingly for ESPert™. Some design parameters were adjusted as requested by Peter Gelfand. These changes are be discussed below.

## DATA SOURCES

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 first source, the field report, details the testing procedure for the Milliken Unit 2 ESP and the results of the performance tests. This report provided the flue gas conditions and particulate statistics as measured at the inlet and exit of both the north and south sides of the Unit 2 ESP. Appendix A of the ESPert™ report lists the coal and ash analyses and the particulate size data excerpted from this field report. Gas flow rates, humidity and temperatures measured during the field test are included in Appendix B of the ESPert™ report. The Milliken data logger provided general operating conditions and an indication of boiler and ESP operating stability during the field test. Averages of the operating parameters required by ESPert™ are listed in Appendix B of the ESPert™ report; selected instantaneous values are presented below. 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. This information is tabulated in the Appendices C and D of the ESPert™ report, respectively.

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 are 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™ report:

Total particulate matter (PM)
Particle size distribution
Flue gas composition ($O_2$ and $H_2O$)
Volumetric flue gas flow rate
Flue gas temperature
Actual fly ash resistivity at the Inlet

For additional measurements, refer to the original field performance report.

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 average was used for the ESPert™ calculations. The fly ash analyses also were averaged.

Two days of sampling were employed for each side of the ESP. While the repeat trials for each side of the ESP were consistent, the result of each individual test was compared with a model prediction rather than using an overall average of the runs on the north and south sides. The required run data are listed in Appendix B of the ESPert™ report.

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 are tabulated in the Appendix A of the ESPert™ report. These results were plotted on

Rosin-Rammler coordinates to obtain an estimate of the performance for the minus 10 µm and minus 2.5 µm fractions. The minus 10 µm and minus 2.5 µm fractions were estimated directly from the data with no smoothing or curve fitting.

During this 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. Penetration is:

$$\text{Penetration} \;=\; 100 - \text{PercentRemoval}$$

or

$$\text{Penetration} \;=\; 100 - \left[\frac{\text{Concentration of Solids in Outlet}}{\text{Concentration of Solids in Inlet}}\right] \bullet 100$$

Penetrations for the minus 10 µm and minus 2.5 µm 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. Thus,

$$\text{Penetration,} < \text{10mmFrac.} = \; 100 - \left[\frac{(\text{Outlet Size,} < \text{10mm Frac.})\bullet(\text{Conc.of Solids in Outlet})}{(\text{Inlet Size,} < \text{10mm Frac.})\bullet(\text{Conc.of Solids in Inlet})}\right] \bullet 100$$

The equation for the minus 2.5 fraction is similar.

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. These are indicated in the appendices of the ESPert™ report by enclosing the value in square brackets, [ ].

For the actual ash resistivity, an average of the results of the four days of testing was used (4.31 x $10^{10}$ ohm-cm). 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 $SO_3$ 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. The measured resistivities are listed in Appendix A of the ESPert™ report. 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.

Figures 3 thru 6 in the ESPert™ report show selected operating parameters for October 17-20, 1995. After reaching maximum generation capacity, approximately 157 $MW_e$, gross, operation of the Unit 2 boiler/generator was stable. Each afternoon, the flue gas temperatures at the inlets to the north and south sides of the ESP increased slightly. This was probably due to the increasing ambient air temperatures. This would reduce the flue gas cooling provided by the combustion air in the heat pipe air heaters upstream of the ESP.

Figures 7 thru 18 in the ESPert™ report show the electrical readings from the TR sets. The figures show that after the generation lined out at the maximum on October 17, the operation of the TR sets was steady.

The ESPert™ report includes Rosin-Rammler plots of the inlet and exit particle size data from the samples collected simultaneously in four trials on October 17, 18, 19 and 20, respectively. The samples from October 17 and 18 were collected on the north-side of the ESP, while the remaining two are from the south-side. This corresponds with the inlet/outlet flue gas sampling on each side of the Unit 2 ESP. The results show low variability for the plus one μm material. Good agreement was obtained for the duplicate tests on each side of the ESP and between the two sides. Only the inlet $D_{50}$ and log-normal standard deviation are used by ESPert™.

Besides the fuel and particulate data discussed above, ESPert™ requires boiler and TR set operating conditions for each run evaluated. These are tabulated in Appendix B of the ESPert™ report. Note that some values requested are for the entire site. Since each side of the ESP was treated separately, some values were adjusted to reflect this. The adjusted values are shown enclosed in parentheses, ( ). The data enclosed in square brackets, [ ], were recommended by P. Gelfand. Data followed by an asterisk, *, were measured at the inlet or outlet to the ESP during the performance field trial.

Design specifications for the ESP's built by Belco Technologies Corp. are tabulated in Appendix B of the ESPert™ report. The order of the specifications is similar to that required by the ESPert™ model. The model also requests general information about the generation facility. This is contained as well in Appendix B of the ESPert™ report.

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, listed in Appendix D of the ESPert™ report, were entered into ESPert™ as full load data according to Gelfand's recommendation. The report includes plots of the various V-I correlations generated by ESPert™ along with the actual data. The model requires non-zero data and has only a limited number of inputs; thus, only the odd (or even) numbered, non-zero points were used. Correlations generated by the model appear to agree with the data. Included on these figures are the correlations estimated by ESPert™. Each correlation is found immediately below its associated plot.

## ESPERT™ COMPARISON

The test results described above were compared with the removals of fly ash predicted by ESPert™. Operational data, listed in Appendix B of the ESPert™ report, along with design specifications (Appendix C) were entered into ESPert™ according to the procedures discussed in the user's manual. The air load V-I values listed in Appendix D of the report 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 than measured at the Milliken ESP. Overall, predicted penetrations using the Model 2 resistivity agreed with those predicted using the AR but were much higher than measured penetrations. Using the Model 1 resistivity, the predicted penetrations were two to three times higher then those predicted by the other 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.

The ESPert™ report includes illustrations of the measured and predicted penetrations at Milliken Station Unit 2. Shown are the measured penetrations along with those predicted by ESPert™ using the AR and the Model 1 and Model 2 ash resistivities. The penetrations for the minus 10 µm and minus 2.5 µm fractions are based on that fraction of the inlet particulate. The average measured penetration for the six tests is also included. Included are plots for total ash, the 10 µm fraction and the minus 2.5 µm fraction. In addition to the total penetration, the penetrations of these two size fractions are predicted by ESPert™.

The measured total penetration is consistently lower than the prediction. Penetrations predicted using the AR and Model 2 resistivity agree with each other and are closer to the measured value than those using the Model 1 resistivity. Compared with the average penetration observed for these six runs, the AR and Model 2 predictions are six to seven times higher than the measured penetrations with Run S3 having the largest error. Run S3 has a higher gas rate, suggesting that this may be one reason that this penetration is underestimated to a greater degree. However, this does not explain the general lack of agreement. The Model 1 predictions are two to four times higher than the AR or Model 2 predicted penetrations; this was unexpected since the Model 1 resistivity is closer to the measured resistivity (or AR).

Similarly, for the minus 10 µm fraction, the Model 1 penetration prediction is the least accurate. The AR and Model 2 penetrations are 4.5 to 6 times the average measured value, while the Model 1 predictions are again 2 to 4 times higher than the other predictions. Thus, the Model 1 predictions are 10 to 22 times higher than the average measured penetration. The penetration predictions are highest for Run S3 as was the case for the total penetration.

The predicted penetrations of the minus 2.5 µm fraction for the AR and Model 2 resistivity are within the experimental error from the average measured value. However, they are consistently higher than the measured penetrations varying between 1.2 and 2 times higher, suggesting some potential bias. Again the Model 1 value is 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.

## ADJUSTMENTS TO ESPERT™

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 is not possible, the second one will be examined next.

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. The revised correlations are listed below their respective plots in the ESPert™ report. These new correlation coefficients were inserted into the ESPert™ model and two of the runs, Run N1 and S3, reevaluated.

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 Runs N1 and S3, and the predicted penetrations plotted. The predictions were compared with the average penetration result from the 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. The bars are labeled to indicate the ratio of the predicted penetration to the average measured penetration.

Adjusting for the V-I correction accounts for about 40% of the higher penetration of the total particulate and the minus 10 µm fraction. The sneakage and velocity sigma adjustments reduce it an additional 10% compared with the original prediction. Applying these corrections to the minus 2.5 µm fraction, the predicted values closely approximate the average measured penetrations. For Run N1, the predicted minus 2.5 µm values are 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 predictions are also over estimated, but are within the accuracy of the original data.

## DIAGNOSTIC REPORTS

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.

### LIMITATIONS OF ESPERT™

Users of this model should note two limitations. First, data cannot be saved directly under a new filename in ESPert™. Instead, copies are made in DOS (or Windows) and edited in ESPert™ to include the data for new trials or units. Secondly, the last TR set will zero out whenever a performance prediction is run with the actual V-I data included for this TR set. That is, the V-I data will disappear and the correlation coefficients will be reset to zero if V-I data are present for the final TR set. The coefficients must be manually entered for the last TR set. As discussed above, the model also repeated the diagnosis notes for all of the evaluated TR sets. This may be a limitation due to the improved control system of the Belco units or the wide plate spacing in these units.

## 4.7.4 CONCLUSIONS

Predictions of ESP penetration using the ESPert™ model are high for an ESP with 16-inch plate spacing firing a medium sulfur bituminous coal. The resistivity estimates for the Model 1 method are close to the actual measurements, but provide much worse estimates of ESP effectiveness than does Model 2's resistivity. Model 2's estimate for resistivity is much lower than the measured value, but the effectiveness estimates are 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.

## 4.8 MILLIKEN- SHU 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 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 and variations in recycle slurry operation relative to $SO_2$ removal, L/G ratio, pressure drop, formate loss, oxidation air utilization and gypsum and chloride brine quality.

### 4.8.1 INTRODUCTION

The New York State Electric and Gas Corporation (NYSEG) has constructed and operated a high-efficiency Saarberg-Hölter Umwelttechnik GmbH (SHU) flue gas desulfurization (FGD) system to demonstrate an innovative emissions control technology and comply with the Clean Air Act Amendments of 1990. The SHU $SO_2$ control technology uses a forced oxidation, formic acid-enhanced wet limestone absorber. The cocurrent-countercurrent absorbers are constructed of Stebbins tile-lined concrete. The technology was expected to reduce $SO_2$ emissions by at least 95%. Project goals included:

- Demonstration of up to 98% $SO_2$ 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.

The SHU process supplemental monitoring program was designed to: (1) maintain process control, and (2) evaluate the effect of operating conditions on $SO_2$ removal efficiency, limestone use, byproduct (gypsum and $CaCl_2$) quality, load following capability, process power consumption, annual operation and maintenance costs and formic acid effectiveness. SHU process control measurements and measurement frequencies are summarized in table 4.8-1. Process control monitoring plans were subject to change during operation phases.

Most of the process control is performed automatically based on data from continuous on-line process monitors. Continuous measurements of flow, temperature, pressure, pressure drop, pH, density , belt or metering pump speed and liquid level are performed using standard commercial industrial process monitors. The accuracy of these monitors was specified during the design phase and verified during installation and shake-down. The $SO_2$ concentration in the gas streams is measured using continuous emission monitors which were installed and operated as prescribed in the Code of Federal Regulations. The plan called for data collection to determine: (1) percent reduction of $SO_2$ achievable, (2) short-term $SO_2$ emissions, (3) 30-day rolling average $SO_2$ emissions, and (4) annual $SO_2$ emissions. Planned non-continuous process control monitoring for the SHU process included laboratory analyses of daily samples to measure formic acid concentration in each side of the absorber and chloride concentration in the blowdown treatment clarified water stream. Utility or industrial boiler operators can use this information to evaluate the economics and environmental acceptability of either the disposal or the by-product sale options.

## TABLE 4.8-1
## SHU PROCESS CONTROL MEASUREMENTS

| Sample Location | Stream Type | Flow | Temp | $SO_2$ Conc | ΔP | Formic Acid Conc | Press | pH | Dens | Belt Speed | $Cl^-$ Conc. | Level Ind. | On/Off Ind. | Moist |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Flue Gas From ID Fan to Absorber(500) | Gas | C | C | C | | | | | | | | | | |
| Flue Gas in Chimney (511) | Gas | C | | C | | | | | | | | | | |
| Pressure Across Absorber (500) & (511) | Gas | | | | C | | | | | | | | | |
| Compressed Oxidation Air to Absorber (504) | Gas | | C | | | | C | | | | | | | |
| Formic Acid to Absorber (504) | Liquid | C | | | | P | | | | | | | | |
| Recycle Absorber Slurry (503) & (502) | Slurry | | | | | D | C | C | | | | | | |
| Limestone Slurry from Slurry Tank (506) | Slurry | | | | | | C | | C | | | | | |
| Total Process Water to System (514) | Liquid | C | | | | | C | | | | | | | |
| Gypsum Slurry to Dewatering (600) | Slurry | | | | | | | | C | | | | | |
| Limestone Feed Belt (400) | Solid | | | | | | | | | C | | | | |
| Clarified Water to Mills (402) | Liquid | C | | | | | C | | | | | | | |
| Gypsum from Centrifuge to Storage (604) | Solid | | | | | | | | | C | | | C | C |
| Clarified Water to Blowdown Treatment (700) | Liquid | C | | | | | | | | | D | | | |
| Filter Cake Wash Water (601) | Liquid | C | C | | | | C | | | | | | | |
| All Process Tanks | Liquid | | | | | | | | | | | C | | |
| Mist Eliminator | Gas | | | | C | | | | | | | | | |

## DESCRIPTION OF THE FGD PROCESS

In the SHU FGD process, a formic acid-buffered limestone slurry reacts with and removes $SO_2$ from the flue gas. In the project design, 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 $SO_2$ is removed. Flue gas enters at the top of the cocurrent section and is contacted with a limestone 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.

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. Using formic acid in the SHU design permits low-pH absorption of $SO_2$ and reduces the potential for scaling and plugging. This creates a stable system that can accommodate rapid changes in inlet $SO_2$ 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 10% 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.

The absorber design incorporates a Stebbins tile-lined, split-module absorber. The absorber is a concrete vessel lined with abrasion- and corrosion-resistant tile. Units 1 and 2 are designed to operate independently so that the flue gas from each boiler is separately treated and discharged. The absorber section does not contain packing or gridwork and, thus, the potential for plugging is greatly reduced.

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.

Gypsum dewatering includes the primary and secondary hydrocyclone systems, filtrate tank, filtrate pumps, and centrifuge. Gypsum slurry is pumped from the absorber sump to the primary hydrocyclones. Overflow slurry from the primary hydrocyclones is piped to the secondary hydrocyclones. Overflow from the secondary hydrocyclones is piped to a clarified water tank to be used for limestone grinding and dilution. A small portion of the clarified water is pumped to the blowdown water treatment system. Underflow from the secondary hydrocyclones is piped to a filtrate tank, which returns filtrate to the absorber. Underflow from the primary hydrocyclones (about 50% solids) is processed by the centrifuges to produce a gypsum cake (90% solids by weight) which is washed by process makeup water to yield a wallboard-quality gypsum. Fresh process water is used as the final wash.

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, suspended solids, and ammonia. 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.

During a scheduled outage or emergency shutdown, the absorber sump contents can be pumped to the absorber slurry storage tank. This slurry is pumped back to the absorber sump before restart of the FGD unit. Housekeeping trenches, sumps, and pumps are provided to collect material from floor washing. This material is pumped to the emergency slurry storage tank as it is collected.

Limestone from the storage pile is conveyed by variable weight-controlled belt 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 $SO_2$ mass loading by regulating the limestone slurry control valve. A limestone slurry density signal is fed to the control valve to compensate for any variation in slurry density. The recycle slurry pH is monitored, but is only used for limestone addition control if the pH exceeds certain minimum/maximum values.

## PROCESS VARIABLES

After a start-up and shakedown period, parametric tests were planned for 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. Although the plan included monitoring load following capability, load was not to be a controlled variable. When possible, load changes during the SHU test period were to be handled by Unit 1 to keep Unit 2 at full load. The same coal was to be fed to both plants simultaneously. The chloride content was not to be a controlled variable; at the design bleed rate (30,000 gal/hr per module), the chloride level was expected to stabilize at about 40,000 ppm $Cl^-$ by weight when burning a 0.1% chlorine coal. Limestone utilization was to be held constant at the design level (1.02). The following is a discussion of the parameters that were to be varied. Oxidation was to be monitored and optimized using an experimental on-line liquid phase sulfite analyzer developed by EPRI.

### Coal Sulfur Content

The plant design is based on a nominal coal sulfur content of 3.2 wt %. The project planned to use Pittsburgh seam coal. The coal sulfur content was to be varied over a range of 1.6 to 4.0 wt % using at least three different coals. The purpose was to demonstrate the SHU technology with lower sulfur coal, design coal, and higher sulfur coal. The test with high-sulfur coal was to be performed only on Unit 2 because the equipment for dewatering and reagent preparation was not designed to handle the output of both units simultaneously using high-sulfur coal. Parametric tests were not to be performed using the high-sulfur coal; the process was to be operated at optimum conditions based on the results of parametric tests using the design coal. The purpose of using high-sulfur coal was to demonstrate the operability of the process using 4% sulfur coal, not to determine the effect of operating parameters on performance.

### Formic Acid Concentration

Formic acid concentrations in the absorber slurry of 0, 400, 800, and 1600 ppm were to be used to demonstrate the effect of formic acid content on $SO_2$ removal, absorber operability, and gypsum quality.

### Spray Header Combination

The testing was to include operating various combinations of spray headers in the cocurrent and countercurrent sections to determine the combination that provides the best $SO_2$ removal performance and lowest absorber energy consumption. The results of these tests were also to be used to determine the mass transfer coefficients individually for the cocurrent and countercurrent sections. The absorber L/G ratio was to be varied by changing the number of spray headers in operation. For each test coal, the pressure drop and $SO_2$ removal were to be measured for each spray header combination used. The gypsum crystal morphology and formic acid consumption rate were to be determined for selected spray header combinations using the design coal only.

### Gas Velocity in the Cocurrent Absorber Section

The design gas velocity in the cocurrent absorber section was 20 ft/sec. Tests at higher velocity (30 to 35 ft/sec) were to be performed on the Unit 2 absorber by shunting some of the gas flow from Unit 1 to provide data on high gas velocity absorbers. These tests were to be performed using two formic acid concentrations (0 and 800 ppm) and two coals (lower sulfur coal and the design coal). The pressure drop and $SO_2$ removal were to be measured for several spray header combinations. The gypsum crystal morphology and formic acid consumption rate were to be determined for selected spray header combinations while using the design coal.

### Limestone Grind Size

The design limestone grind size is 90% -170 mesh when using formic acid and 90% -325 mesh using no formic acid. For comparison purposes, tests were planned using 90% -170 mesh limestone without formic acid and using 90% - 325 mesh limestone at 800 ppm formic acid concentration in the absorber.

## 4.8.2 LOW SULFUR COAL TESTING AND EVALUATION

The low sulfur (1.6% S) coal parametric tests of the Saarberg-Holter-Umwelttechnik GmbH (SHU) flue gas desulfurization (FGD) process were conducted by CONSOL R&D and NYSEG at NYSEG Milliken Station Unit No. 2 from October 11 to November 21, 1995. A test report was written by CONSOL and NYSEG and is available from DOE upon request. The report is entitled: “Milliken Clean Coal Technology Demonstration Project, The SHU Low Sulfur Flue Gas Desulfurization Summary Report at Milliken Station, August 1997.”, What follows is a summary of this test report.

### INTRODUCTION

The Saarberg-Holter Umwelttechnik GmbH (SHU) flue gas desulfurization (FGD) process began operating on Milliken Station Unit 2 in January 1995 and on Unit 1 in June 1995. The 1.6% sulfur coal parametric tests of the SHU process were performed from October 11 to November 21, 1995. Details of the project test plan and test schedule are given in “Detailed Test Plan for the 1.6 % Sulfur Test of the SHU Absorber at the NYSEG Milliken Station," available from DOE upon request.

The objectives of the 1.6% sulfur coal test program were:

- To demonstrate the effect of formic acid recycle slurry concentration on $SO_2$ 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 $SO_2$ removal.
- To determine the effect of limestone grind size on $SO_2$ removal.

### CONCLUSIONS

The following are the major conclusions of the 1.6% sulfur coal test program:

### $SO_2$ Removal

- $SO_2$ 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 $SO_2$ removal was 98% at a 95% confidence interval of ± 0.7% (absolute).

- $SO_2$ removal was increased significantly by formic acid. For example, using five spray headers, $SO_2$ removal averaged 82% without formic acid and 97% with 800 ppm formic acid.

- The parametric tests were performed at a pH of 4.2 ± 0.25. Six tests without formic acid were performed at a higher pH set point (pH of 5.0 ± 0.05). At the higher pH, increased $SO_2$ removal was observed for the same spray header configurations. For example, using all seven spray headers, $SO_2$ removal was 94.4% at pH 5.05 without formic acid compared to 90.2% at pH 4.21 with formic acid.

- Nine tests were performed using an alternate limestone grind size. Higher $SO_2$ removal was observed using the finer grind (90%-325 mesh) limestone than with the coarser grind (90% - 170 mesh) limestone. The average difference in $SO_2$ removal between the two grind sizes was 2.6 percent (absolute).

- $SO_2$ removal during the high velocity tests ranged from 91% to 98%. At an equivalent L/G, more $SO_2$ was removed during the high velocity tests than during the design velocity tests. For example, $SO_2$ removal averaged 95% at 94 gal/kacf in the design velocity tests and 97% at 89 gal/kacf in the high velocity tests.

### Pressure Drop

- Cocurrent L/G had no measurable effect on pressure drop, whereas countercurrent L/G significantly increased the absorber pressure drop.

### Mass Transfer

- Mass transfer increased with increasing L/G, but the effect was not always a linear function of L/G.

- Formic acid increased the mass transfer; however, the effect diminished with increasing formic acid concentration.

- Mass transfer during the high gas velocity tests was higher than in the design velocity tests at similar L/G.

## EXPERIMENTAL METHODS

There are four cocurrent spray headers (Headers "A" through "D") and three countercurrent spray headers (Headers "E" through "G") in each SHU module (figure 4.8.2-1). To protect the Stebbins tile-lined absorber from high flue gas temperature, at least one of the top two headers on the cocurrent side ("A" and "B") must be operating at all times. The combinations of operating spray headers used in this study are:

| Cocurrent | Countercurrent |
|---|---|
| 4 | 3 |
| 4 | 2 |
| 4 | 1 |
| 4 | 0 |
| 3 | 3 |
| 3 | 2 |
| 3 | 1 |
| 3 | 0 |
| 2 | 3 |
| 2 | 2 |
| 2 | 1 |
| 2 | 0 |
| 1 | 3 |
| 1 | 2 |

Each of these combinations was tested with and without formic acid; each test was performed twice. For each combination, the upper-most headers in either section were used. In this report, the header configurations are represented as a pair of numbers designating the number of cocurrent and counter-current headers in operation; for example, (4,3) means four cocurrent and three countercurrent spray headers in operation. The results from tests using no countercurrent sprays (4,0; 3,0; 2,0) 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.

Parametric tests were performed on Unit 2 to define the performance limits of the SHU FGD system. 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 $Cl^-$ 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 $SO_2$ concentration and flue gas flow rate at the absorber inlet; trim control is based on absorber slurry pH, which prevents excursions during major process changes such as load swings. During these tests, the pH control loop was used to maintain a constant absorber chemistry despite widely changing $S0_2$ 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 $SO_2$ 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 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 in this report. Mass transfer was calculated for the cocurrent and countercurrent sections using the design flow values.

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.

Each test was performed for four-to-six hours; the absorber data ($SO_2$ removal, pressure drop, pH, etc.) usually reached equilibrium within one to three hours. Test data were averaged over a one-to-three hour period following the equilibration of the system. Data were collected using the plant's data logging system.

## RESULTS AND DISCUSSION

The test conditions and results are listed in table 4.8.2-1. Figure 4.8.2-2 summarizes the results, showing the general effects of liquid-to-gas ratio and formic acid concentration for tests using at least two countercurrent headers. The maximum $SO_2$ removal was achieved using the (4,3) and (3,3) header configurations 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). The following is a discussion of the variable effects on $SO_2$ removal, pressure drop, and mass transfer.

### $SO_2$ Removal

The following table summarizes the test conditions which achieved better than 90% $SO_2$ removal.

Cocurrent and Countercurrent Headers vs. $SO_2$, Removal. Limestone grind = 90% -170 mesh except tests with Δ which were 90%-325 mesh; pH = 4.2 unless otherwise indicated.

| | Design Gas Velocity | | | High Gas Velocity |
|---|---|---|---|---|
| Nominal Formic Acid Concentration: | 0 ppm | 400 ppm | 800 ppm | 800 ppm |
| >95% $SO_2$ Removal | (4,3)Δ 5.0 pH | (4,3)<br>(3,3)<br>(3,2) Δ | (4,3)<br>(3,3)<br>(2,3)<br>(1,3)<br>(4,2)<br>(3,2) | (4,3)<br>(3,3)<br>(2,3)<br>(4,2)<br>(3,2) |
| 90 to 95% $SO_2$ Removal | (4,3)Δ<br>(3,3)Δ | (2,3)<br>(4,2)<br>(3,2)<br>(2,2) | (2,2)<br>(1,2)<br>(4,1)<br>(3,1)<br>(2,1)Δ | (2,2)<br>(4,1)<br>(3,1) |

The following is a discussion of the effects of test variables on $SO_2$ removal.

**The effect of liquid to gas ratio (L/G).** In wet absorbers, an increase in the liquid to gas ratio represents an increase in the reactive slurry flow rate per unit volume of gas and also an increase in the droplet surface area for mass transfer to take place; as a result, more $SO_2$ is removed. This is illustrated by figures 4.8.2-3 through 5 which show $SO_2$ removals for each test level of formic acid as a function of total L/G, based on the design slurry flow rate to the headers. The lines drawn in figures 4.8.2-3 through 5 are based on the correlation equations given later in this report for NTU as a function of L/G and formic acid concentration.

The $SO_2$ removal without formic acid addition is shown in figure 4.8.2-3. The results are separated based on the number of countercurrent headers operating. The average removal ranged from a low of 30% at 45 gal/kacf to a high of 90% at 167 gal/kacf. There was a significant difference in $SO_2$ removals depending upon the number of countercurrent headers in use. For example, the removals using (4,0), (3,1), and (2,2) gave average removals of 50%, 64%, and 74%, respectively, although they each provide a total L/G of 90-100 gal/kacf. In general, the data show that more $SO_2$ removal is achieved when a higher percentage of the total slurry is sprayed in the countercurrent section.

When formic acid was used, the effect of countercurrent L/G on $SO_2$ removal was significant but the effect diminished with increasing formic acid concentration. In the 400 ppm formic acid tests (figure 4.8.2-4), 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 (figure 4.8.2-5), 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 higher than the nominal values as described earlier.

**Effect of formic acid**. The addition of formic acid increases the buffer capacity of the absorber slurry solution and, thus, yields a higher concentration of dissolved calcium in the slurry solution at a given pH. Figures 4.8.2-6 to 9 show $SO_2$ removal as a function of the measured formic acid concentration in the absorber slurry for four, three, two, and one cocurrent headers, respectively. The lines drawn in figures 4.8.2-6 through 9 are based on the correlation equations given later in this report for NTU as a function of L/G and formic acid concentration. The data in each figure are grouped according to the number of countercurrent spray headers operating. The formic acid concentrations were determined by the titration method described in Appendix A of the “SHU Low Sulfur Flue Gas Desulfurization Summary Report”. The measured concentrations typically were higher than the nominal concentrations, especially in the 800 ppm tests. The figures show that formic acid causes the $SO_2$ 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 $SO_2$ removal.

**Effect of pH.** Increasing the pH from 4.2 to 5.0 without formic acid additive increased the $SO_2$ removal (figure 4.8.2-10). With cocurrent sprays only, the removal averaged 6.5% (absolute) higher at pH 5.0 than at pH 4.2; using cocurrent and countercurrent sprays together, the removal averaged 10.1% (absolute) higher at pH 5.0 than at pH 4.2.

**Effect of limestone grind size.** More $SO_2$ was removed using 90% - 325 mesh limestone than using 90% -170 mesh limestone. Figure 4.8.2-11 compares $SO_2$ removal for the two different grind sizes at pH 4.2 as a function of total L/G; the spray header configurations used were (4,3), (3,2), and (2,1). The average difference in $SO_2$ removal between the two grind sizes was 2.6 percent (absolute). The effect was greatest at the intermediate formic acid concentration.

**Effect of Gas Velocity.** $SO_2$ 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 $SO_2$ was removed during the high velocity tests than during the design velocity tests, as shown by figure 4.8.2-12. 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. Figure 4.8.2-13 shows the relationship between the pressure drop and the number of countercurrent headers for all of the design gas velocity and high gas velocity tests. 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 regression equation obtained from the data for absorber pressure drop (in inches of water column) for the design gas flow rate is:

$$\Delta P = 0.48 + 0.45 \text{ x No. of countercurrent spray headers operating}$$

with an $r^2$ of 0.977 (97 degrees of freedom). The regression equation for the high gas velocity data is:

$$\Delta P = 1.89 + 0.64 \text{ x No. of countercurrent spray headers operating}$$

with an $r^2$ of 0.933 (12 degrees of freedom).

The cocurrent spray headers had no significant effect on the pressure drop. Figure 4.8.2-14 shows the relationship between the pressure drop and the number of cocurrent headers for the design gas velocity tests. A statistical F-ratio test confirms the significance of the countercurrent headers and the lack of significance of the cocurrent headers on the absorber pressure drop. An example of the statistical F-ratio tests is provided in Appendix B of the test report.

### Mass Transfer

Mass transfer is discussed in terms of the number of transfer units (NTU), which is derived from the two-film theory of mass transfer. This theory assumes that the bulk gas-phase and bulk liquid-phase are well mixed and that the concentration of $SO_2$ is constant throughout both bulk phases. All mass transfer is assumed to occur in a gas-phase and liquid-phase boundary layer. The equation derived from theory is:

$$NTU = 1n\left(\frac{SO_2 \text{ in}}{SO_2 \text{ out}}\right) = \frac{K_g \cdot A \cdot P \cdot V}{G}$$

Where:
NTU = number of transfer units (dimensionless)
$SO_2$ in = concentration of $SO_2$ at the absorber inlet (ppmv)
$SO_2$ out = concentration of $SO_2$ at the absorber exit (ppmv)
$K_g$ = global mass transfer coefficient (mol/cm$^2$-sec-atm)
A = interfacial mass transfer area per unit volume (cm$^2$/m$^3$)
P = absolute absorber pressure (atm)
V = absorber volume (m$^3$)
G = molar gas flow rate (mol/sec)

The pressure and absorber volume are constant. The $SO_2$ removal is affected by the global mass transfer coefficient, the mass transfer area, and the gas flow rate. The global mass transfer coefficient is a combination of the gas-phase and liquid-phase mass transfer coefficients, generally written as:

$$K_g = \left( \frac{1}{k_g} + \frac{H}{e \cdot k_1} \right)^{-1}$$

Where:

$k_g$ = gas phase mass transfer coefficient (mol/cm$^2$-sec-atm)

$k_1$ = liquid phase mass transfer coefficient (cm/sec)

H = Henry's Law constant for $SO_2$ in the absorber liquid (atm/mol/l)

e = an enhancement factor to account for diffusion of $SO_2$ through the liquid as bisulfite or sulfite (dimensionless)

The global mass transfer coefficient is affected by any process variable which affects the physical or chemical properties of the two boundary layers. For example, additives such as formic acid increase the buffer capacity of the liquid, which decreases H. The enhancement factor, e, decreases with increasing $SO_2$ concentration. The gas distribution and absorber geometry affect $k_1$. All of these affect the liquid phase mass transfer resistance, $H/(ek_1)$. $k_g$ is affected by the absorber geometry. Also, countercurrent water/gas flow tends to have higher $k_g$ than cocurrent water/gas flow because the gas phase boundary layer is thinner in countercurrent flow. Increasing the liquid flow rate increases the number of droplets, which increases the interfacial mass transfer area, A. Increasing the gas flow rate, G, decreases the residence time in the absorber, but can also increase the gas phase mass transfer coefficient by decreasing the gas phase boundary layer thickness.

Thus, determining the effect of process variables on mass transfer is complicated because of the number of variables and the complexity of each variable's effect. Common industry practice has been to plot NTU as a function of L/G, which is often (but not necessarily always) a linear function when everything else is held constant. This type of plot will be used in the following discussion of the effect of several variables on mass transfer. It is assumed that the fresh water quench at the absorber inlet and the fresh water mist eliminator wash at the absorber exit do not contribute significantly to the $SO_2$ removal or overall mass transfer. Combined, the inlet quench and mist eliminator wash contribute 100 to 200 gpm, which is a total L/G of 0.2 to 0.4 gal/kacf, insignificant amounts compared to the test design range of 45 to 170 L/G.

**Cocurrent L/G.** The mass transfer in the cocurrent section of the SHU absorber increased with increasing L/G (figure 4.8.2-15). The fourth (bottom) cocurrent header had less effect on mass transfer than the first three, especially at high formic acid concentration.

Figure 4.8.2-15 shows NTU vs cocurrent L/G for the tests without formic acid, 400 ppm and 800 ppm formic acid. All of these tests were performed without countercurrent headers operating. The figure shows lines based on the correlation equations given later in this report for NTU as a function of L/G and formic acid concentration. The lines are drawn through the origin because at zero L/G the $SO_2$ removal should be zero. At the highest L/G, which is achieved using Header "D", the bottom cocurrent header appears to have less effect than the first three. 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. This will be examined during the design sulfur coal tests to see if the same behavior occurs.

The slope of the NTU vs L/G lines for the tests without countercurrent sprays was used to calculate the NTU for each cocurrent spray header. A least squares fit, forced through the origin, was used to obtain the slope. The mass transfer is listed separately for each header in the following table.

| | Target Formic Acid Concentration: | none | 400 ppm | 800 ppm |
|---|---|---|---|---|
| | Slope of NTU vs. L/G for (2,0) and (3,0): | 0.0081 | 0.0135 | 0.0161 |
| Header A | Average L/G (gal/kacf) | 24.9 | 24.9 | 25.5 |
| | Average NTU = slope x L/G | 0.202 | 0.336 | 0.412 |
| Header B | Average L/G (gal/kacf) | 24.9 | 24.9 | 25.5 |
| | Average NTU = slope x L/G | 0.202 | 0.336 | 0.412 |
| Header C | Average L/G (gal/kacf) | 24.9 | 24.9 | 25.5 |
| | Average NTU = slope x L/G | 0.202 | 0.336 | 0.412 |

Only the (2,0) and (3,0) tests were used to obtain these slopes, since the effect of the fourth header is less than the first three. Also, the results of one of the (2,0) tests without formic acid, test S-L-0-10, were not included because the pH during that test (4.7) was significantly higher than the targeted test pH of 4.2 ± 0.25. The NTU for Header "D" was calculated by subtracting the average (3,0) test NTU from the average (4,0) test NTU. This gives an average NTU for Header "D" of 0.117, 0.159, and 0.025 in the 0, 400, and 800 ppm formic acid tests, respectively.

**Countercurrent L/G.** 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.

In this analysis it is assumed that mass transfer in the cocurrent section was the same whether the countercurrent headers were off or on. Thus, by subtracting the cocurrent NTU from the total absorber NTU, the countercurrent NTU can be determined. The mass transfer in the countercurrent section without cocurrent sprays could not be measured directly because the design of the absorber required that at least one cocurrent header be operating at all times. Figures 4.8.2-16 through 18 show total NTU minus the cocurrent NTU (I.e., the countercurrent NTU) vs countercurrent L/G for the tests without formic acid, 400 ppm and 800 ppm formic acid, respectively. Different symbols are used to represent the different number of cocurrent headers in operation, so that tests can be compared on an equivalent cocurrent L/G basis.

An average NTU for each countercurrent header was calculated by subtracting the NTU obtained during tests without countercurrent spray from the corresponding test with countercurrent sprays; the results are listed in the following table along with the average L/G for each header.

| Target Formic Acid Concentration: | | none | 400 ppm | 800 ppm |
|---|---|---|---|---|
| Header E | Average L/G (gal/kacf) | 24.9 | 24.9 | 25.5 |
| | Average NTU | 0.448 | 1.026 | 1.544 |
| Header F | Average L/G (gal/kacf) | 24.9 | 24.9 | 25.5 |
| | Average NTU = slope x L/G | 0.622 | 0.695 | 0.692 |
| Header G | Average L/G (gal/kacf) | 24.9 | 24.9 | 25.5 |
| | Average NTU | 0.499 | 0.447 | 0.504 |

**Formic Acid Concentration.** The mass transfer increased 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.

The formic acid concentration during each test was determined by the titration method given in Appendix A of the test report. The effect of formic acid was determined by comparing the mass transfer in tests using the same header configuration with and without formic acid. Figures 4.8.2-19 through 22 show $NTU_{formic}$ minus $NTU_0$ vs the measured formic acid concentration for four, three, two, and one cocurrent headers, respectively; $NTU_{formic}$ is the NTU observed during tests with formic acid and $NTU_0$ is the NTU observed in the same test without formic acid. Different symbols are used to represent different cocurrent headers in operation. Formic acid concentration had a stronger impact on NTU when countercurrent headers were used. Without countercurrent headers the best fit is obtained with the formic acid concentration raised to the 0.5 power; with countercurrent headers, the best fit is with formic acid raised to the 0.75 power.

For tests without formic acid:

$$\begin{aligned} NTU = {} & 0.0081\,(Cocurrent\ L/G - 0.4''D''\ L/G \\ & + (Countercurrent\ L/G\left[0.0135 + 0.000104\left(Cocurrent\ L/G - 0.4''D''\ L/G\right)\right] \end{aligned}$$

For tests with formic acid:

$$\mathrm{NTU} = 0.0081\ (\mathrm{Cocurrent\ L/G} - 0.4\text{"D"}\ \mathrm{L/G}\left[1 + 0.923\left(\frac{\mathrm{ppm\ formic\ acid}}{800}\right)^{0.5}\right]$$

$$+ \left(\frac{0.662\ \mathit{countercurrent\ L/G}\left(\frac{\mathit{ppm\ formic\ acid}}{800}\right)^{0.75}}{1 + 0.0137\ \mathit{countercurrent\ L/G}\left(\frac{\mathit{ppm\ formic\ acid}}{800}\right)^{0.75}}\right)$$

where "D" L/G means the liquid-to-gas ratio being sprayed by the "D" header. The lines drawn in the figures in this report are based on these correlation equations. Figure 4.8.2-23 is a parity plot showing the predicted NTU using these equations vs the measured NTU for the 84 parametric tests. A linear regression of the measured vs predicted values gives an $R^2$ value of 0.970 (83 degrees of freedom).

**Gas Velocity.** The mass transfer during the high gas velocity tests was greater than in the design velocity tests at similar L/G ratios due to a reduction in the gas phase diffusion resistance. The high gas velocity tests were performed at a target formic acid concentration of 800 ppm. For the high velocity tests, the plot of NTU vs the total L/G is shown in figure 4.8.2-24; the NTU for design velocity tests at a target 800 ppm formic acid using the same header configuration are shown for comparison. The results clearly show greater mass transfer for the high 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 $SO_2$ concentration (due to coal sulfur variability) and the chloride content in the absorber slurry.

The inlet $SO_2$ concentration slowly decreased over the 42-day test period. During the tests without formic acid the inlet $SO_2$ averaged 1000 ppm; the average decreased to 970 ppm and 879 ppm $SO_2$ during the 400 and 800 ppm formic acid tests, respectively. The sulfur contents of the coal samples taken during the test period are given in Appendix C of the test report.

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 $SO_2$ 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. Figure 4.8.2-25 shows no discernible effect of chloride concentration on $SO_2$ removal 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. In addition, during periods of time, the chloride concentration correlated with the measured formic acid concentration as shown in Figure 4.8.2-26. A probable explanation for this is that when chloride is removed by the blowdown treatment system, some formic acid is removed also. Thus, when the chloride level was allowed to build up, the formic acid level increased. When the chloride level was brought back under control, the formic acid level was reduced also.

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 ±0.25 of the set point. For the design gas velocity tests the boiler load was 158 ±2.5 gross MWe, giving a absorber inlet gas flow of 490 ±8 kacfm. For the high velocity tests, the combined Unit 1 and Unit 2 boiler load was 213 ±11 gross MWe, giving a gas flow of 721 ±35 kacfm. The absorber inlet gas temperature averaged 298 $\pm 13^{o}$ F in the design velocity tests and 276 $\pm 7^{o}$ 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. This will be addressed during the longer term tests (approx. 5 days duration) which will be performed during the design sulfur coal tests.

**Lab Analyses.** Laboratory analyses were performed on thirteen gypsum samples. The results are shown in table 4.8.2-2. 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. Gypsum crystal morphology will be examined during week long tests in the design coal test phase.

**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. Operability will be examined in detail during the longer term tests using the design sulfur coal. 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 $SO_2$ 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 $SO_2$ 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. A complete material balance, including major and trace elements, will be performed during the design sulfur coal tests.

## DATA ACCURACY AND PRECISION

The parametric tests were performed in duplicate. The statistical analysis of replicate sampling runs using a pooled standard deviation provides a means of measuring the plant's reproducibility. Reproducibility refers to the agreement among results of replicate tests. Reproducibility as determined by the pooled standard deviation method is affected by all process uncertainties, including process measurement uncertainty, process control variation, process performance variation, the effect of uncontrolled variables (inlet temperature and flow rate, inlet $SO_2$ concentration, absorber slurry pH, chlorides) and data accuracy. That is, the reproducibility includes uncertainty in the measured $SO_2$ removal as well as variability in the independent variables which determine the removal (e.g., L/G, gas flow, slurry pH, etc.).

The pooled standard deviation is calculated using the following formula:

$$S_{pooled} = \sqrt{\frac{(n_1 - 1)\,S_1^{\,2} + (n_2 - 1)\,S_2^{\,2} + \cdots + (n_k - 1)\,S_k^{\,2}}{(n_1 - 1) + (n_2 - 1) + \cdots + (n_k - 1)}}$$

where

$n_j$ = the number of repeat measurements for the $j^{th}$ test, j = l,...,k
$S_j$ = the standard deviation of the $j^{th}$ test
k = total number of tests, not including replicates

Tables 4.8.2-3 to 5 show the pooled standard deviation of controlled and uncontrolled process variables for the parametric tests. The reproducibility confidence band is calculated by multiplying Student's t-statistic ($t_{95\%}$ for the corresponding degrees of freedom at a 95% confidence level) by the pooled standard deviation. There were 14 degrees of freedom for each parameter. The confidence band divided by the average measured value within the range gives the confidence band as a percentage of the measured value.

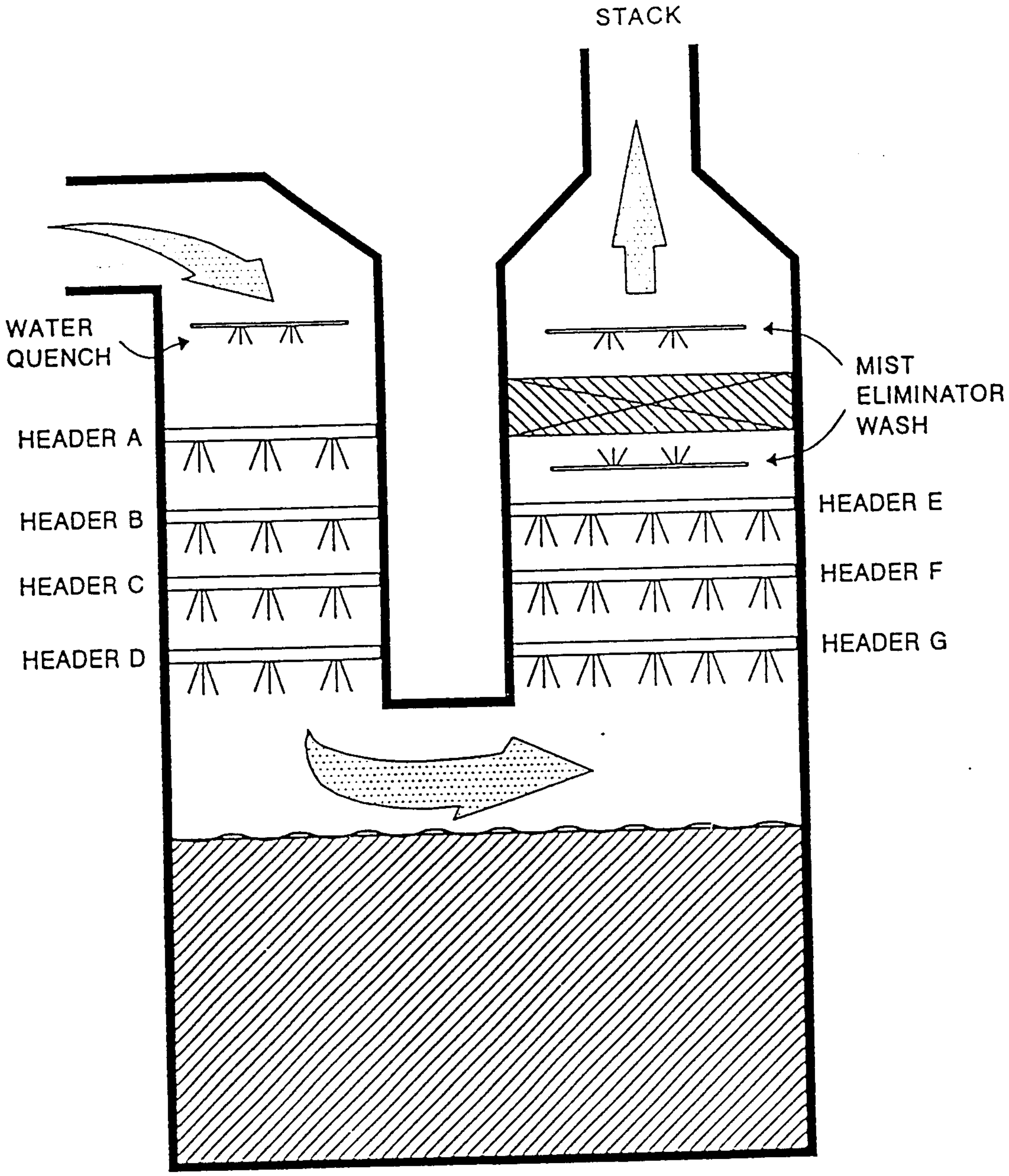
Table 4.8.2-3 shows poor reproducibility for the formic acid concentration. At a 95% confidence level, the formic acid reproducibility was ±167 ppm and ±375 ppm in the nominal 400 ppm and nominal 800 ppm tests, respectively, which is ±38% (relative) of the average measured formic acid concentrations of 462 and 981 ppm, respectively. This reproducibility is worse than expected, but as explained earlier, the formic acid concentration was affected by the plant's waste water treatment schedule.

The reproducibilities of the pressure drop and NTU are also given in table 4.8.2-3. At 95% confidence limits, the reproducibilities of the pressure drop was ±0.17 "$H_2O$ or less and NTU was ±0.26 or less. In other words, when a test is performed in which an NTU of 2.75 is measured, a repeat test should give 2.75 ±0.26 (or between 2.49 and 3.01) 95% of the time. These reproducibilities are less than ±10% of the average value, except for the pressure drop in the 400 ppm formic acid tests, which was ±14% of the average value. These are considered to be good reproducibilities, considering that the tests were performed on a full-scale unit, with variations in the flue gas flow, temperature, absorber slurry pH, chlorides, or other process conditions or fluctuations.

The reproducibility of the $SO_2$ removal was best at the highest $SO_2$ removals (table 4.8.2-4). Tests giving over 95% $SO_2$ removal were reproducible to within ±1.0% (absolute), while tests giving 90 to 95% $SO_2$ removal were reproducible to within ±1.6% (absolute). Between 70 and 90% $SO_2$ removal, the reproducibility was ±3.9%. At less than 70% $SO_2$ removal, the reproducibility was ±5.2% (absolute). The reason for the changing reproducibility arises from the calculation of $SO_2$ removal. $SO_2$ removal is calculated from the flue gas $SO_2$ concentration measured at the absorber inlet and outlet (stack). At high removals, the outlet $SO_2$ concentration was low and variations in the outlet concentration had a small effect on $SO_2$ removal. For example, if the outlet concentration increased by 25% from 20 ppm (98% removal) to 25 ppm (97.5% removal) the difference in removal was only 0.5% (absolute). However, at lower removals the outlet $SO_2$ concentration was higher and variations in the outlet concentration had a more significant effect on $SO_2$ removal. For example, if the outlet $SO_2$ concentration increased by 25% from 200 ppm (80% removal) to 250 ppm (75% removal) the difference in removal was 5% (absolute).

The reproducibility for pH gross boiler load, and absorber inlet gas flows and temperatures, were all within ±5.2% (relative) as shown in table 4.8.2-5. The relative stability of these uncontrolled variables contributed to the good reproducibility of the $SO_2$ removal, NTU, and pressure drop. The reproducibility for the inlet gas $SO_2$ was not as good. At a 95% confidence level, inlet $SO_2$ reproducibility ranged from 4.7% to 20.7% (relative). The inlet $SO_2$ was dependent on the sulfur content of the coal being burned and the excess air firing rate and, thus, beyond the control of FGD plant operations.

**FIGURE 4.8.2-1**
**SHU ABSORBER SCHEMATIC SHOWING HEADER DESIGNATIONS**



## FIGURE 4.8.2-2

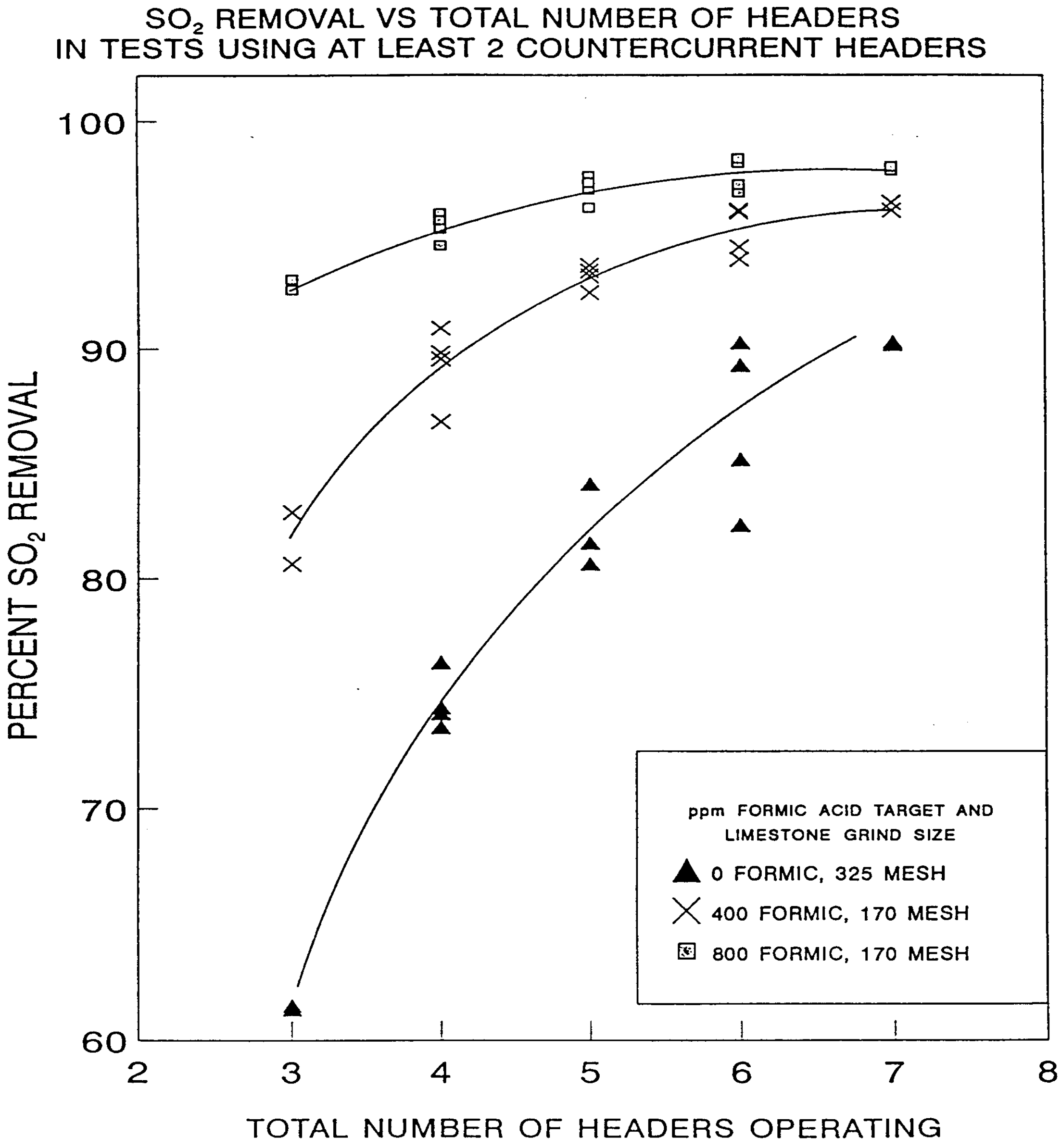


Figure 2. Summary of $SO_2$ Removal Results for Tests Using at Least Two Countercurrent Spray Headers.

**FIGURE 4.8.2-3**

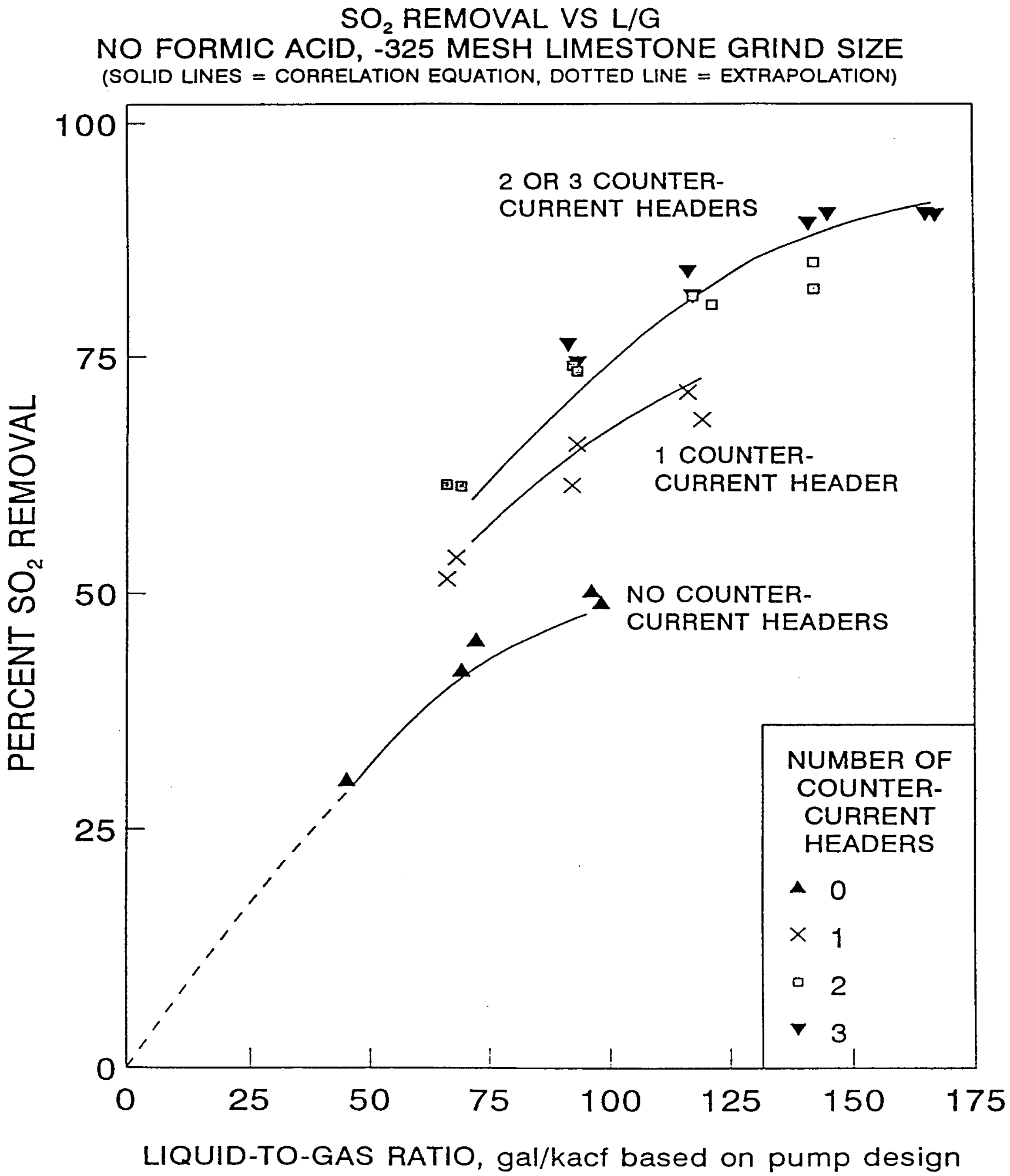
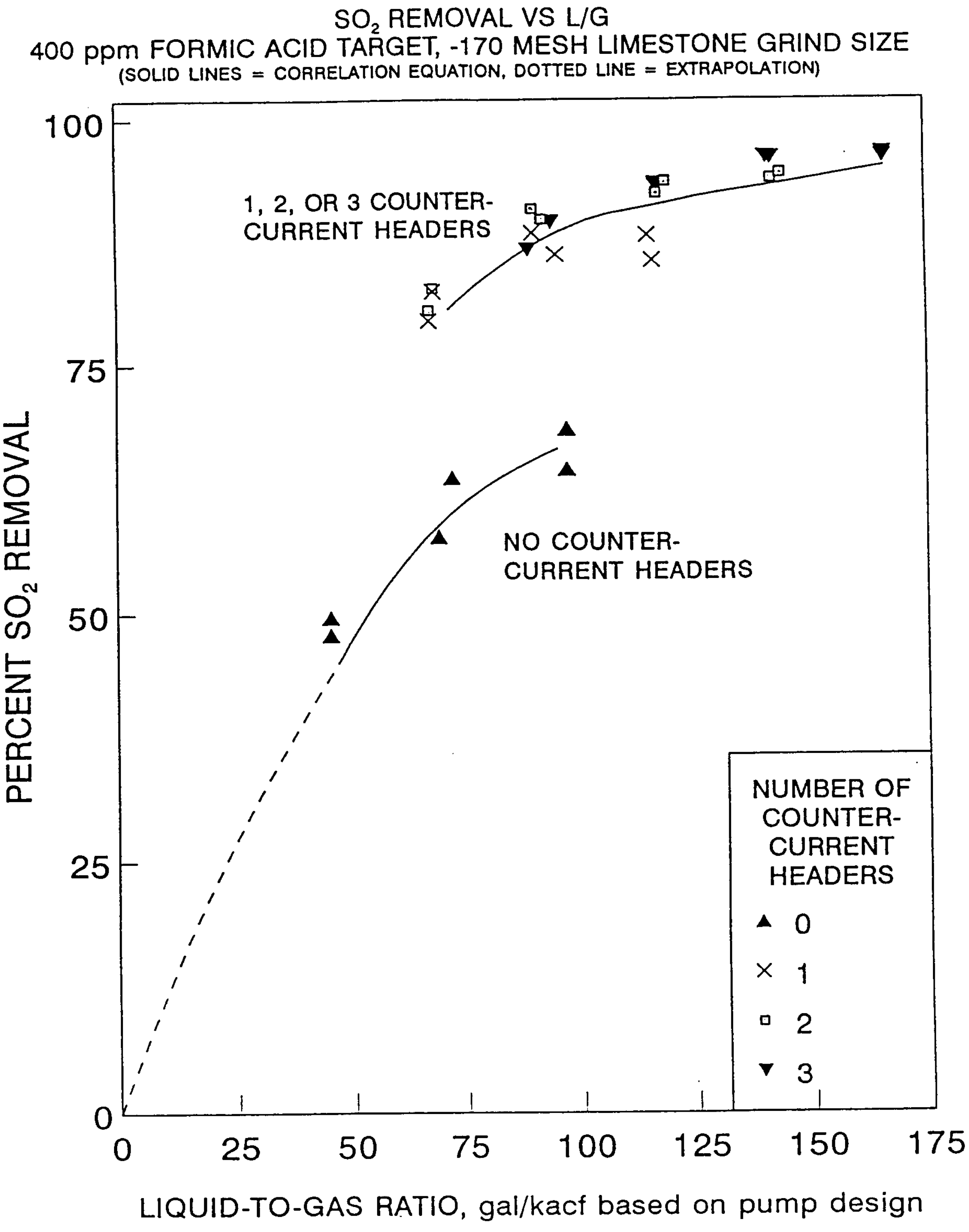


Figure 3. $SO_2$ Removal vs Total L/G, Tests Without Formic Acid.

**FIGURE 4.8.2-4**



$SO_2$ REMOVAL VS L/G
400 ppm FORMIC ACID TARGET, -170 MESH LIMESTONE GRIND SIZE
(SOLID LINES = CORRELATION EQUATION, DOTTED LINE = EXTRAPOLATION)

Figure 4. $SO_2$ Removal vs Total L/G, Tests With Nominally 400 ppm Formic Acid.

**FIGURE 4.8.2-5**

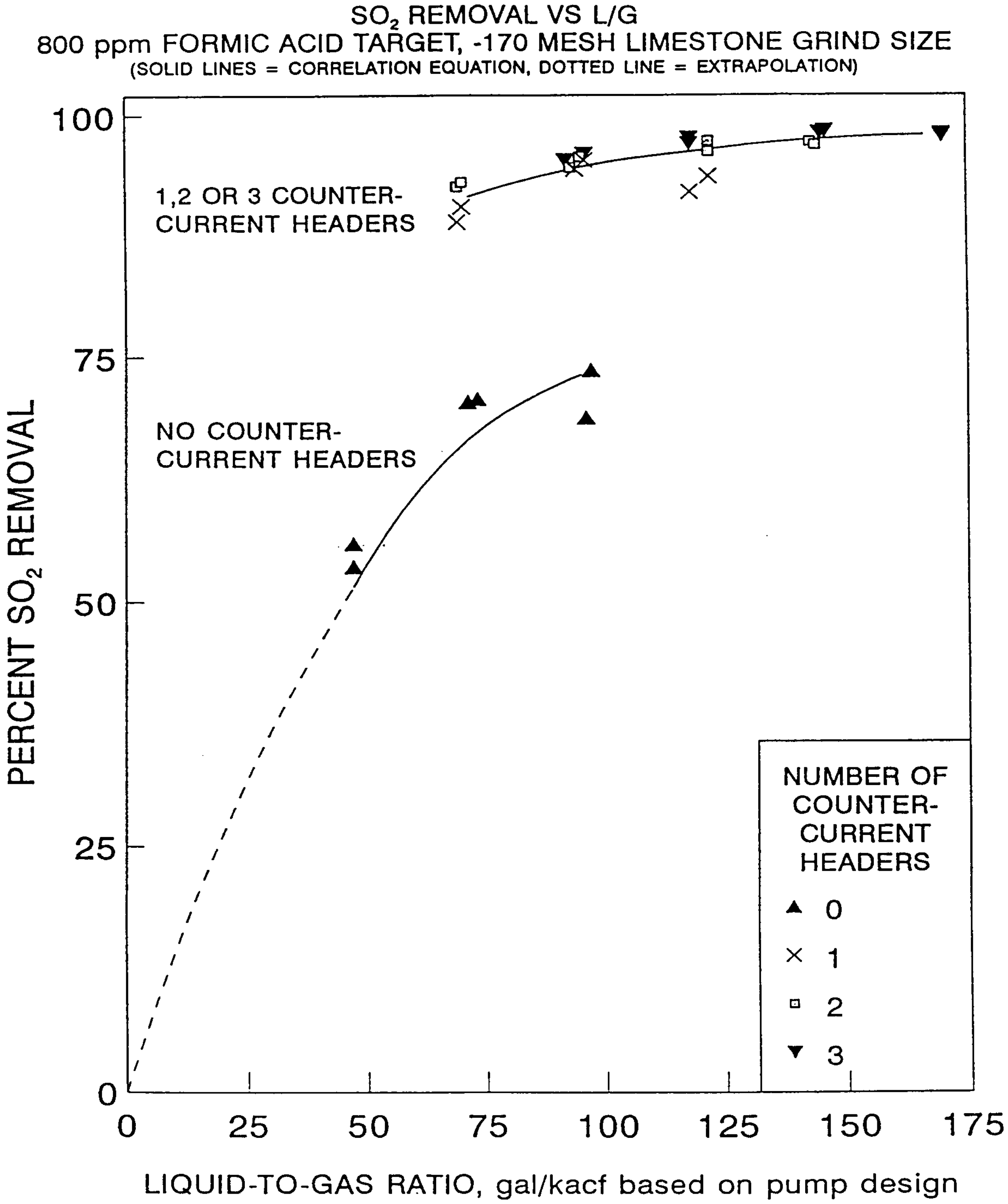


Figure 5. $SO_2$ Removal vs Total L/G, Tests With Nominally 800 ppm Formic Acid.

## FIGURE 4.8.2-6

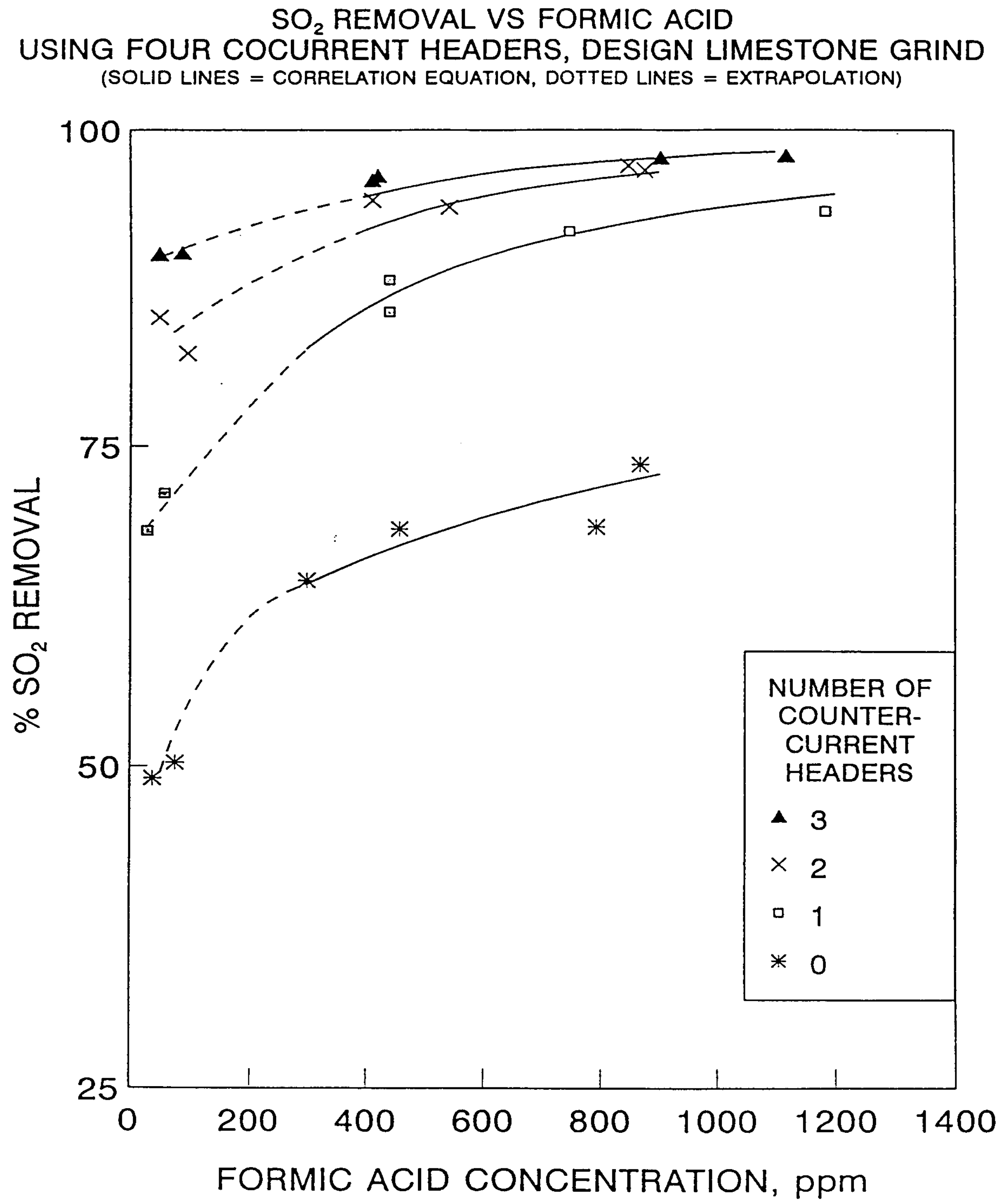


Figure 6. $SO_2$ Removal vs Formic Acid Concentration, Tests Using Four Cocurrent Headers.

## FIGURE 4.8.2-7

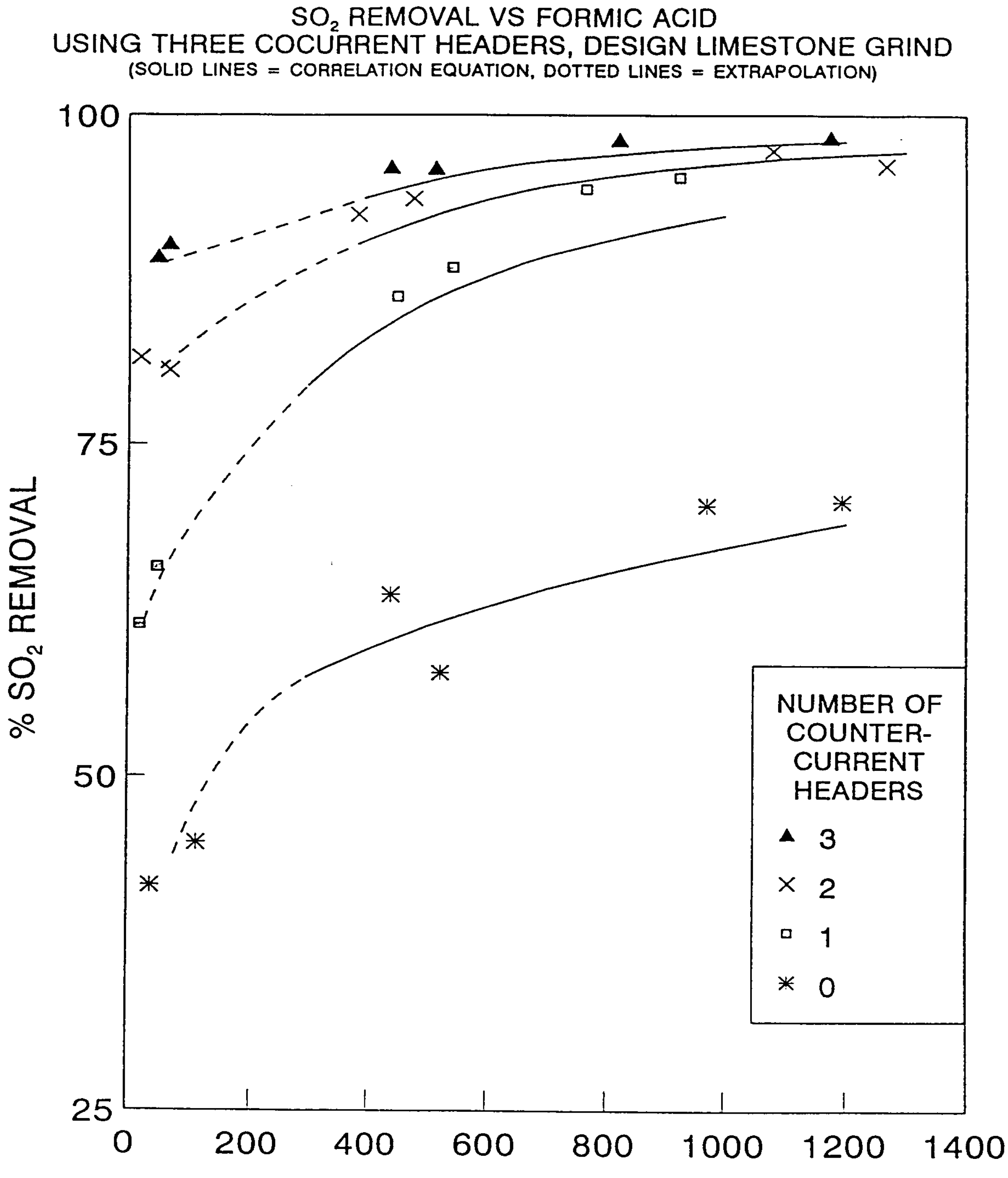


Figure 7. SO$_2$ Removal vs Formic Acid Concentration, Tests Using Three Cocurrent Headers.

## FIGURE 4.8.2-8

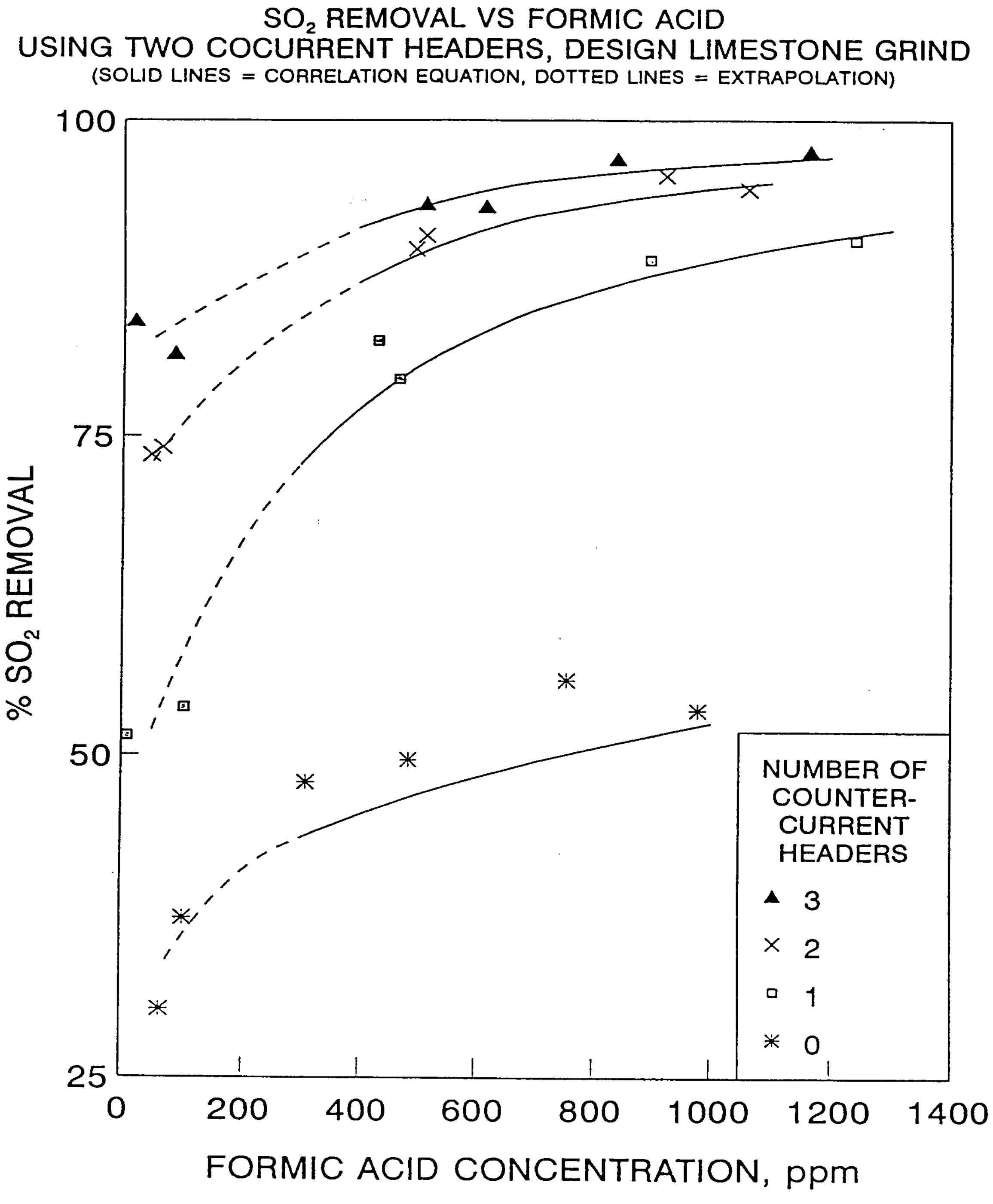


Figure 8. SO$_2$ Removal vs Formic Acid Concentration, Tests Using Two Cocurrent Headers.

**FIGURE 4.8.2-9**

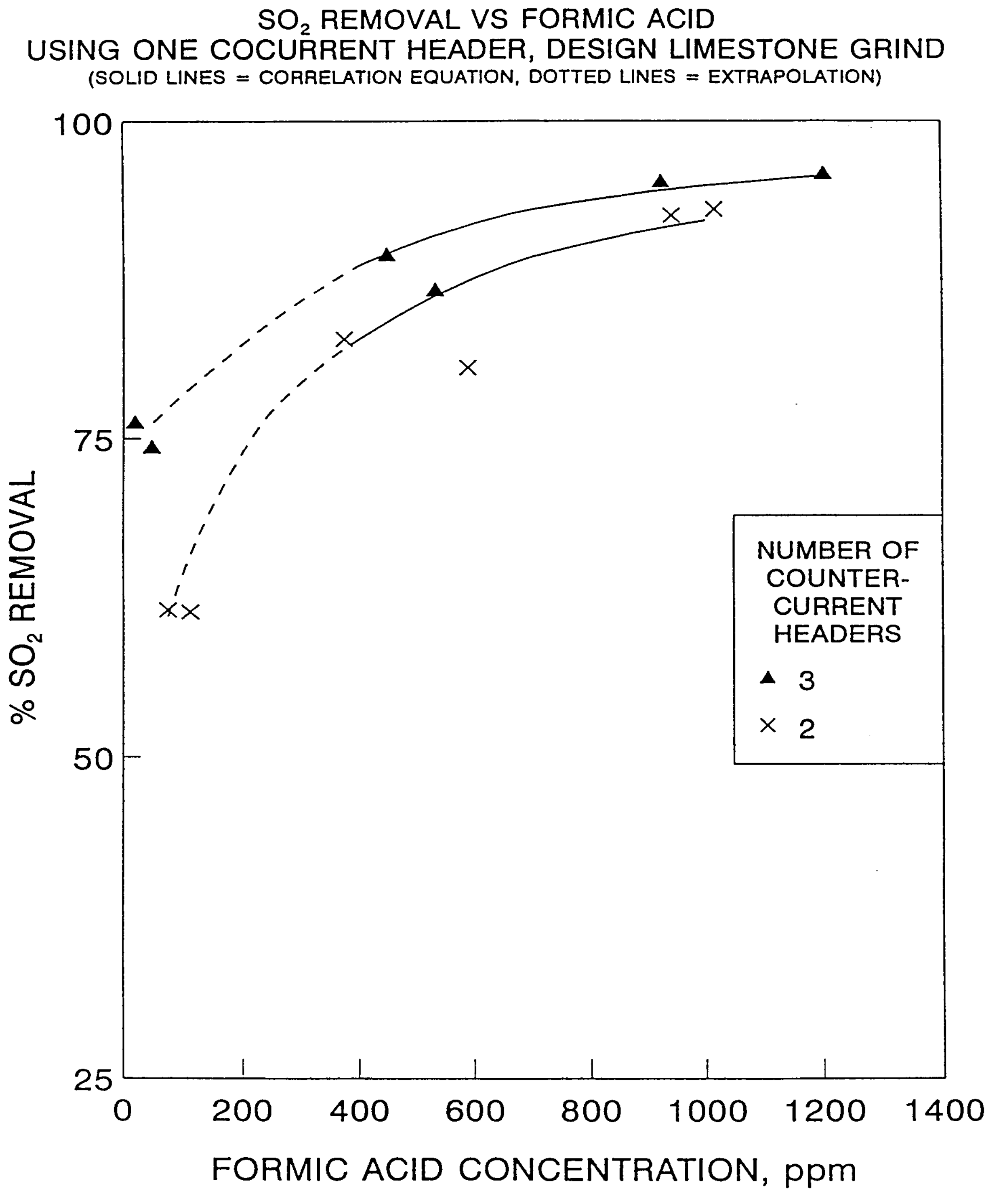


Figure 9. $SO_2$ Removal vs Formic Acid Concentration, Tests Using One Cocurrent Header.

## FIGURE 4.8.2-10

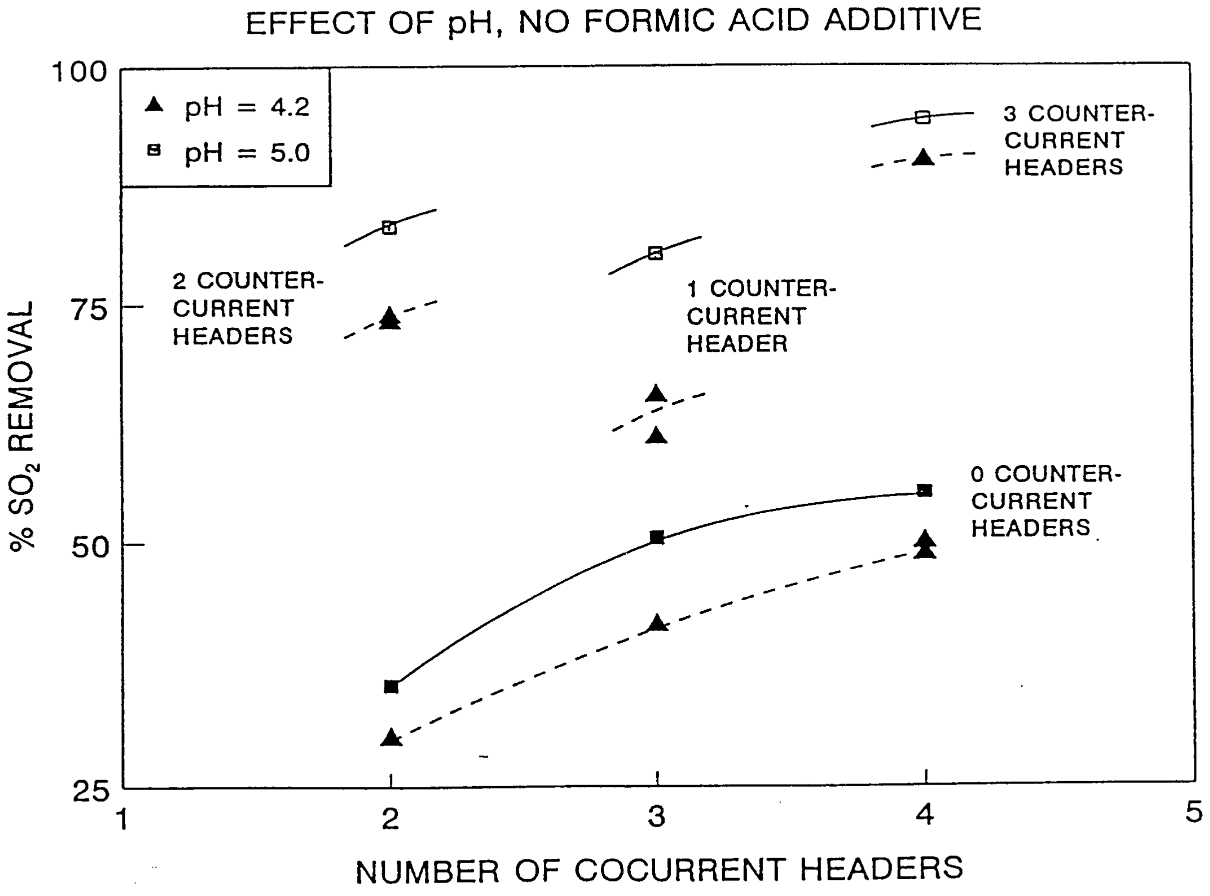


Figure 10. $SO_2$ Removal vs Number of Cocurrent Headers Showing the Effect Of pH.

## FIGURE 4.8.2-11

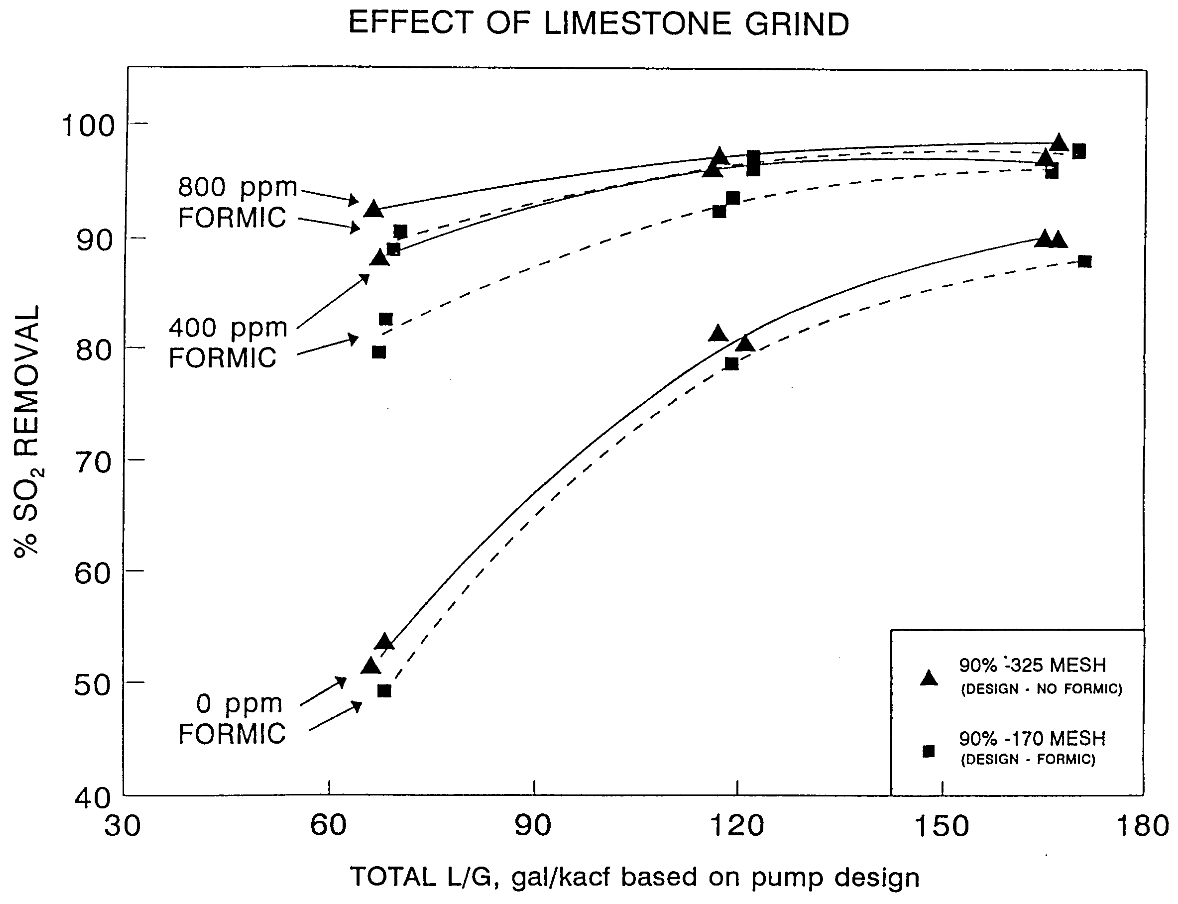


Figure 11. $SO_2$ Removal vs Total L/G Showing the Effect of Limestone Grind Size.

## FIGURE 4.8.2-12

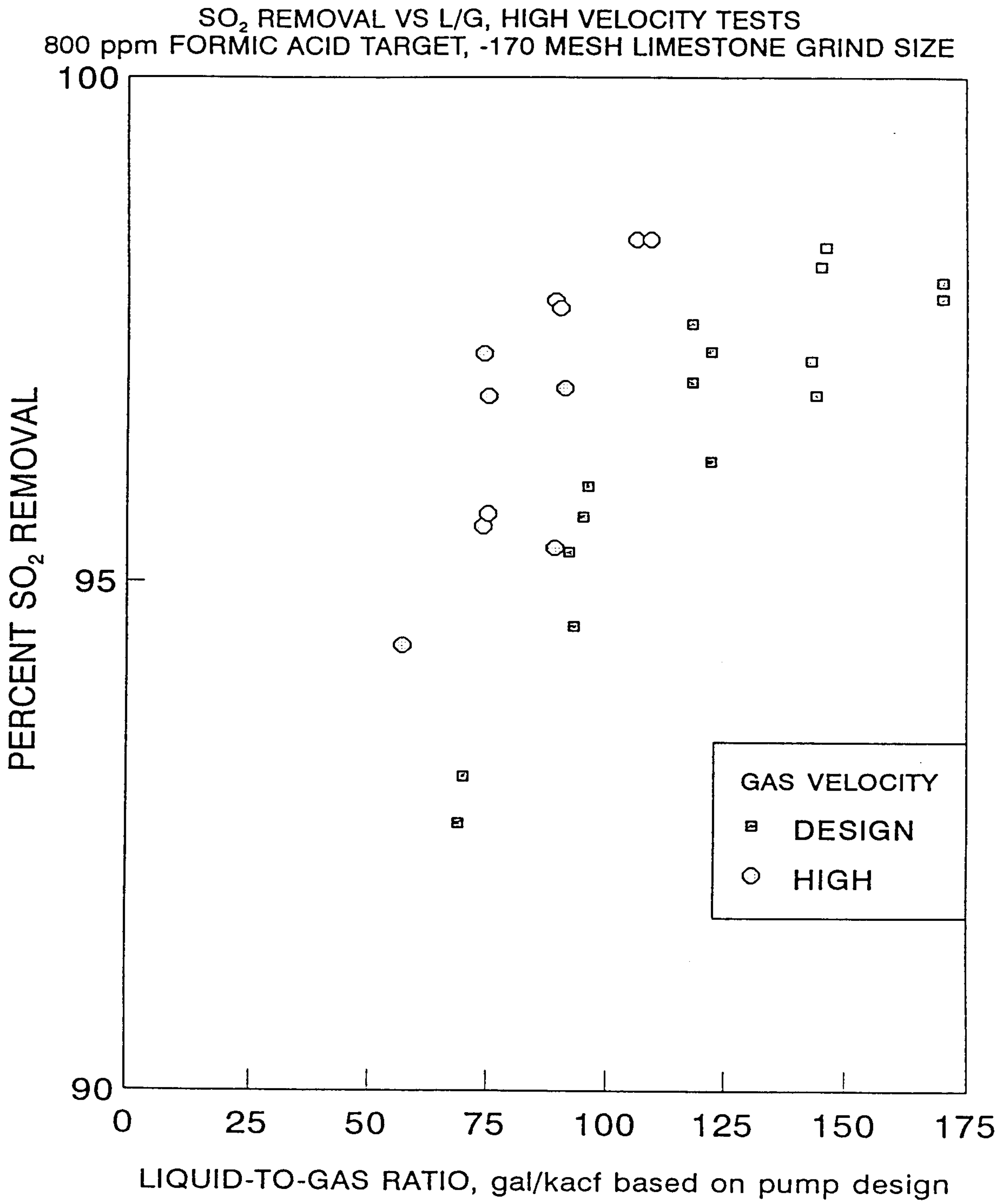


Figure 12. SO$_2$ Removal vs Total L/G Showing the Effect of Gas Velocity.

**FIGURE 4.8.2-13**

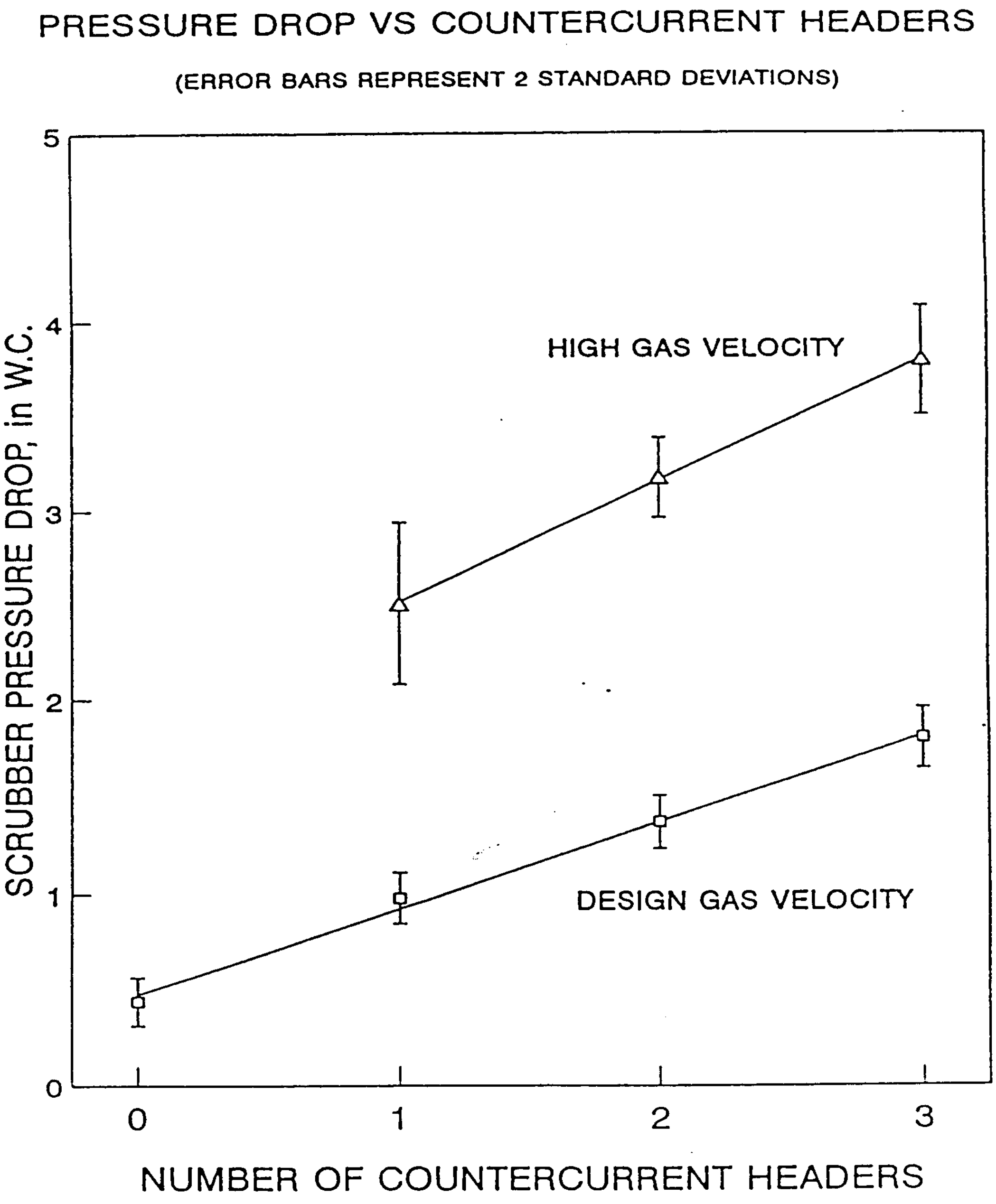


Figure 13. Scrubber Pressure Drop vs Number of Countercurrent Headers Operating.

**FIGURE 4.8.2-14**

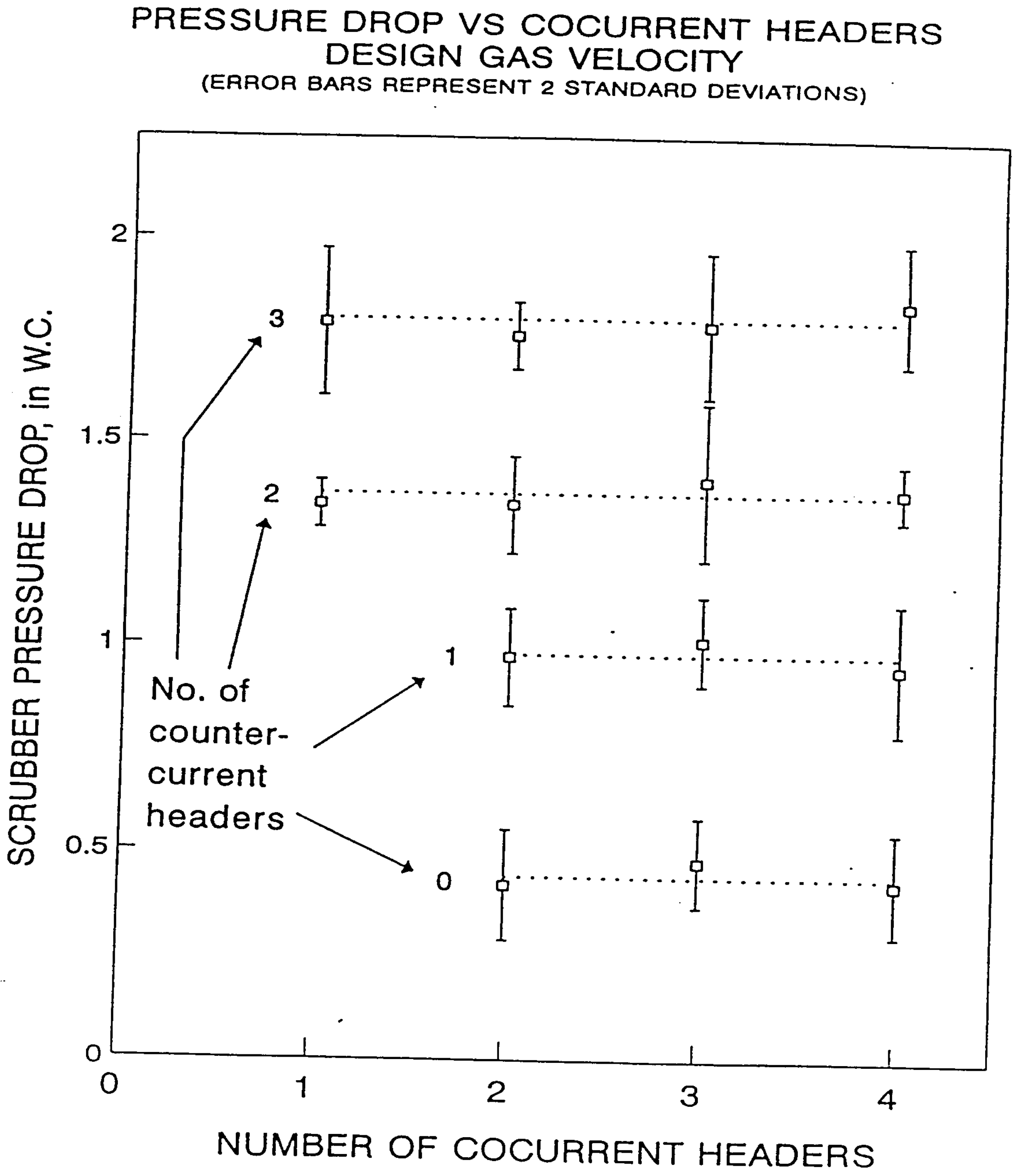


Figure 14. Scrubber Pressure Drop vs Number of Cocurrent Headers Operating.

## FIGURE 4.8.2-15

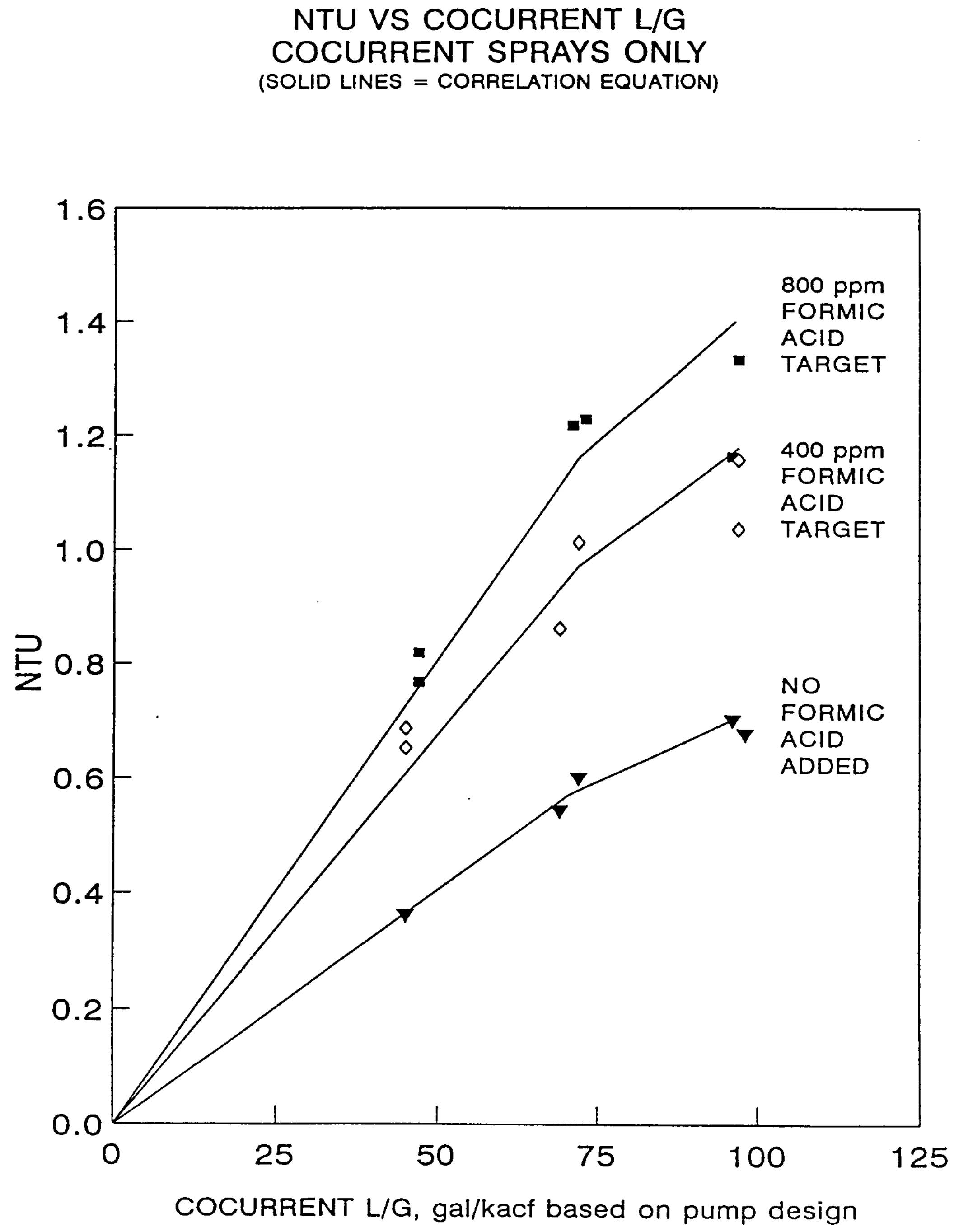


Figure 15. Number of Transfer Units vs Cocurrent L/G
Without Countercurrent Headers Operating.

**FIGURE 4.8.2-16**

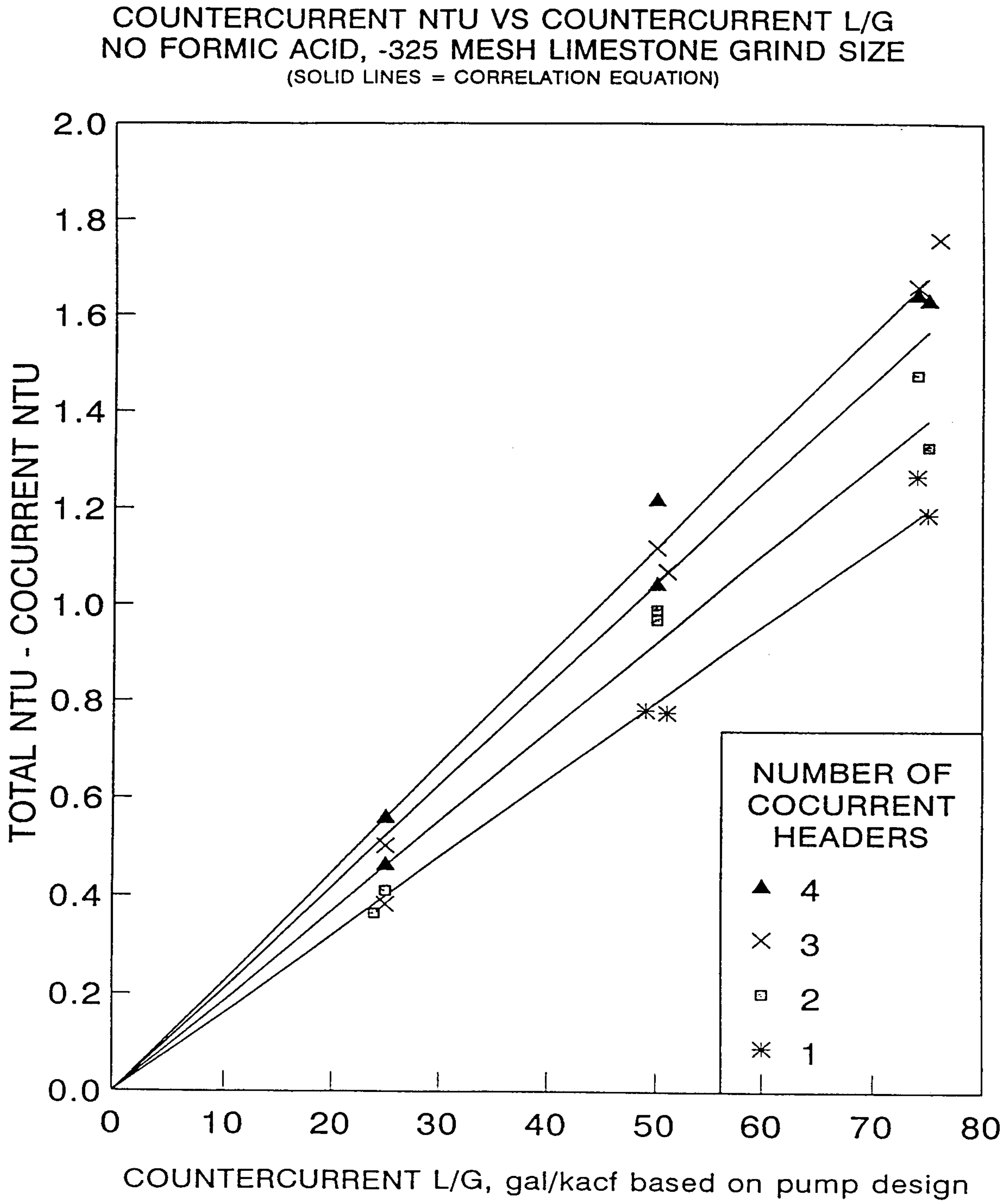


Figure 16. Number of Transfer Units vs Countercurrent L/G
Without Formic Acid.

## FIGURE 4.8.2-17

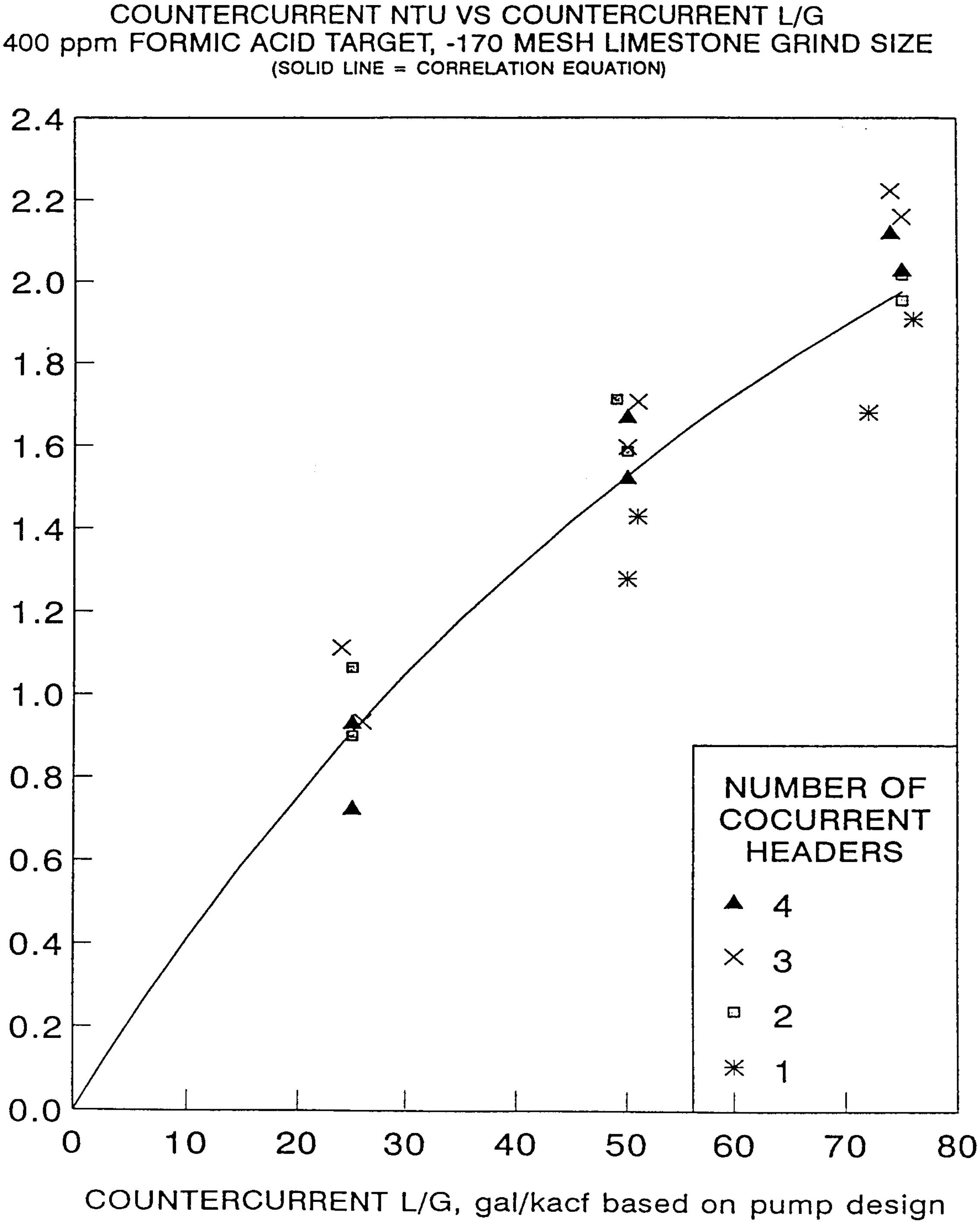


Figure 17. Number of Transfer Units vs Countercurrent L/G With Nominally 400 ppm Formic Acid.

## FIGURE 4.8.2-18

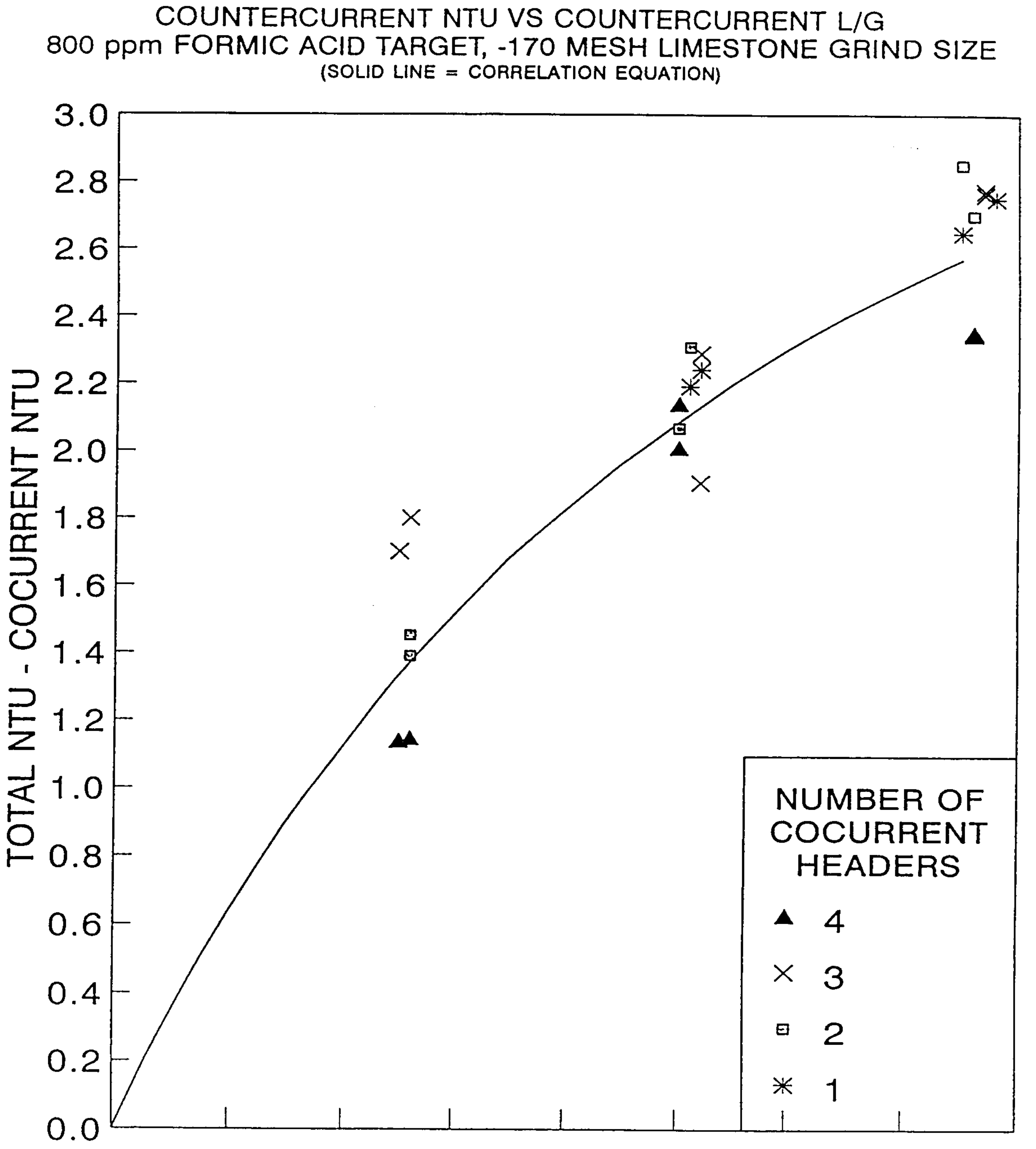


Figure 18. Number of Transfer Units vs Countercurrent L/G
With Nominally 800 ppm Formic Acid.

## FIGURE 4.8.2-19

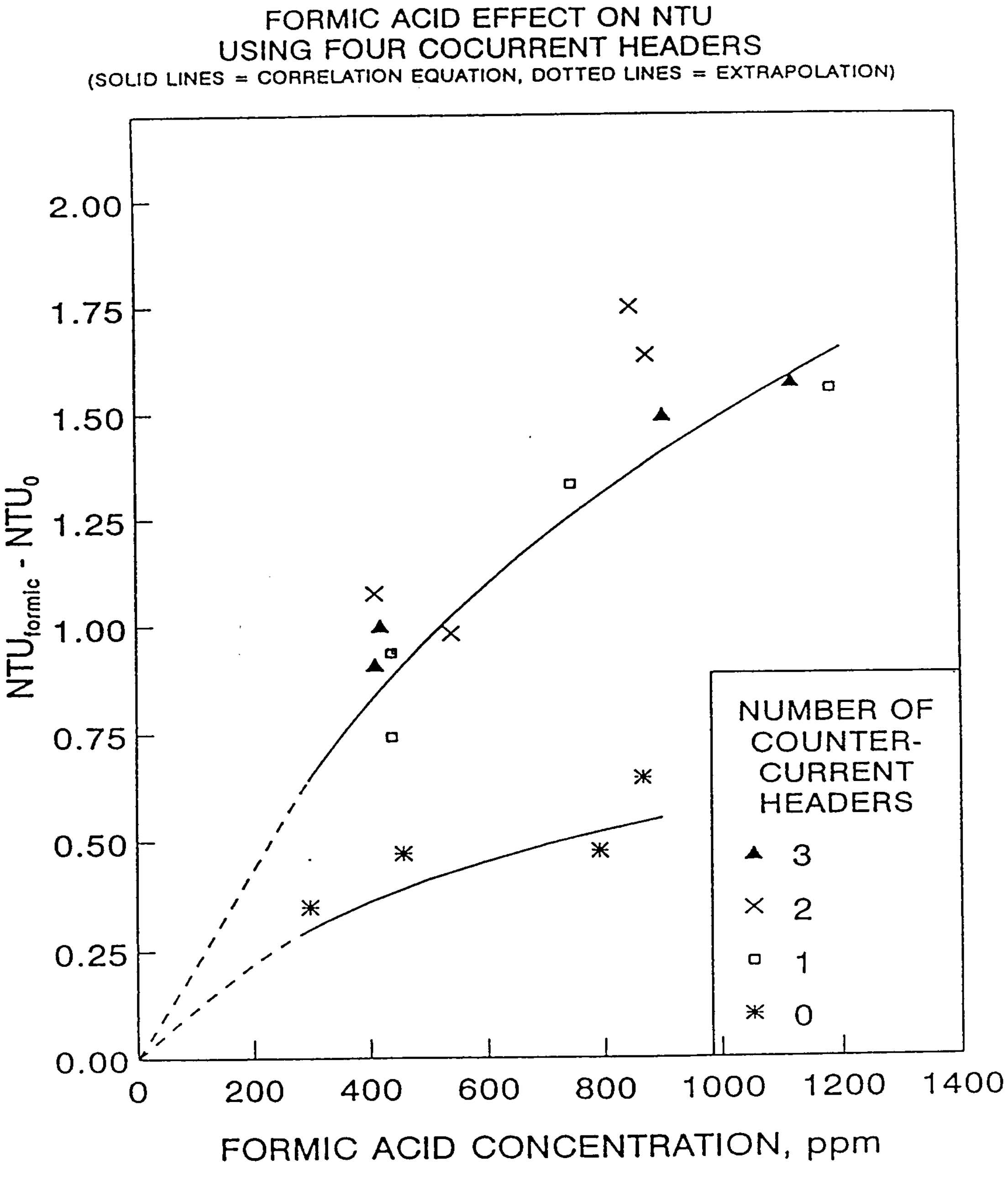


Figure 19. $NTU_{formic}$ minus $NTU_0$ vs Formic Acid Concentration, Tests Using Four Cocurrent Headers.

## FIGURE 4.8.2-20

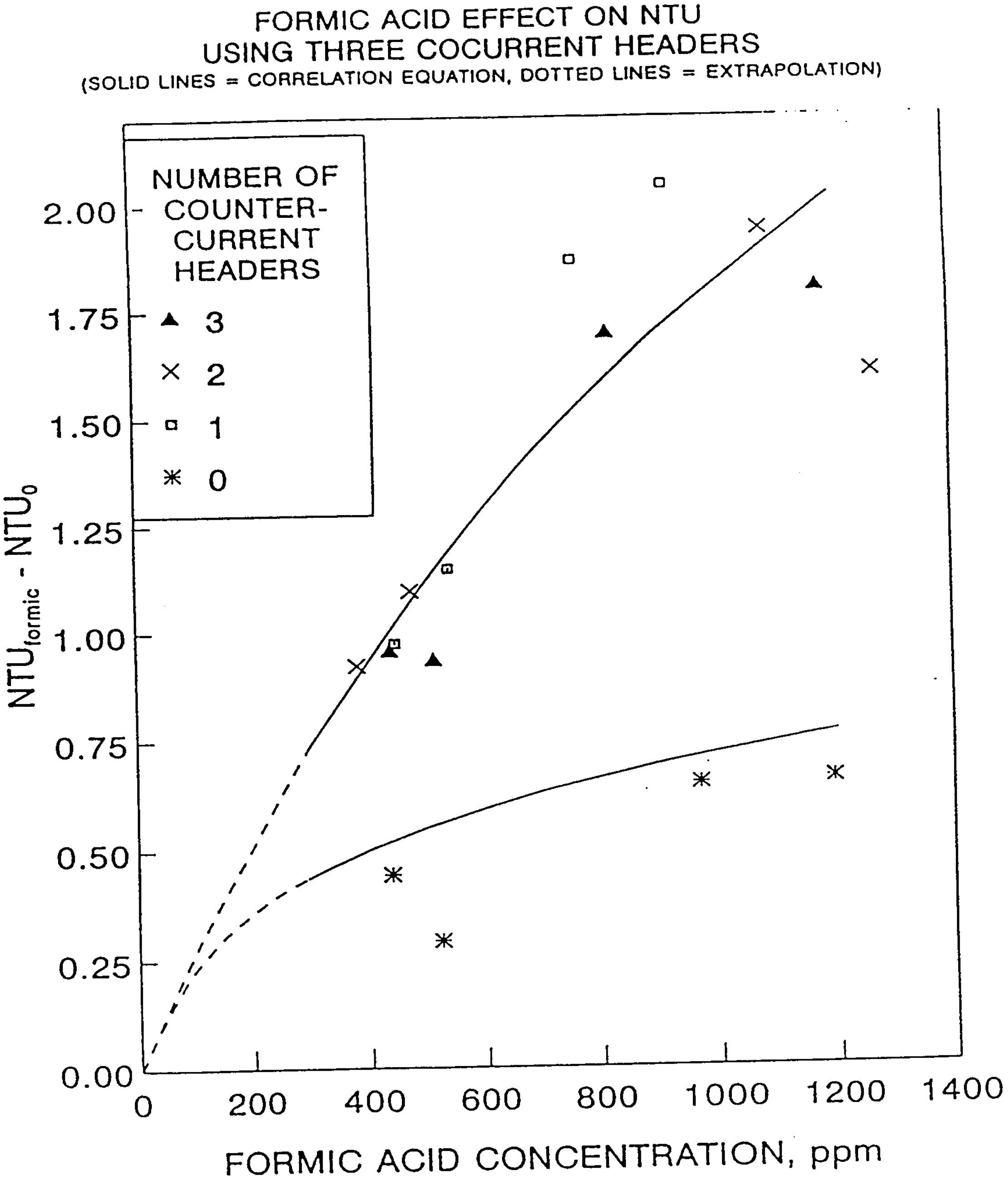


Figure 20. $NTU_{formic}$ minus $NTU_0$ vs Formic Acid Concentration, Tests Using Three Cocurrent Headers.

## FIGURE 4.8.2-21

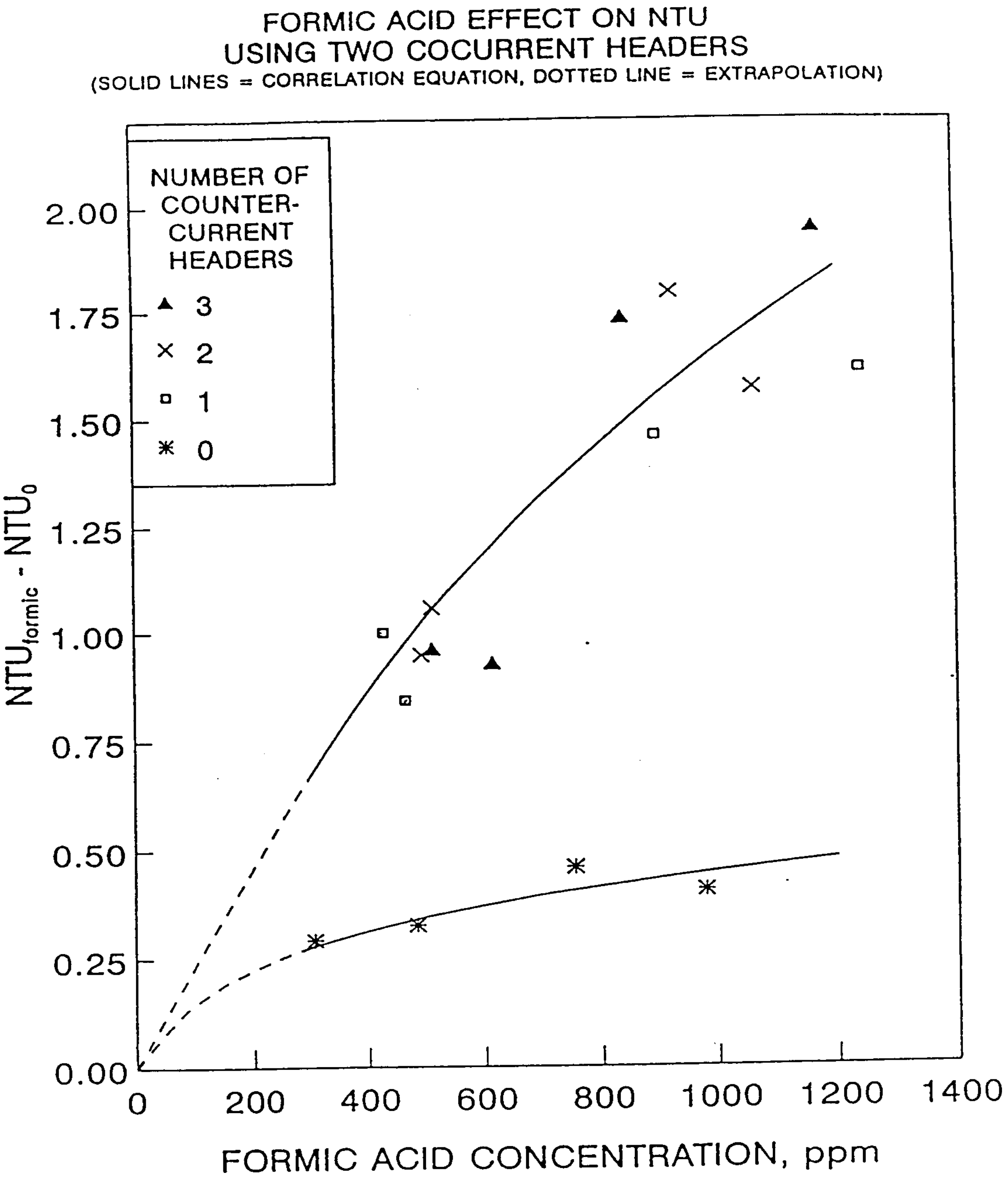


Figure 21. $NTU_{formic}$ minus $NTU_0$ vs Formic Acid Concentration, Tests Using Two Cocurrent Headers.

**FIGURE 4.8.2-22**

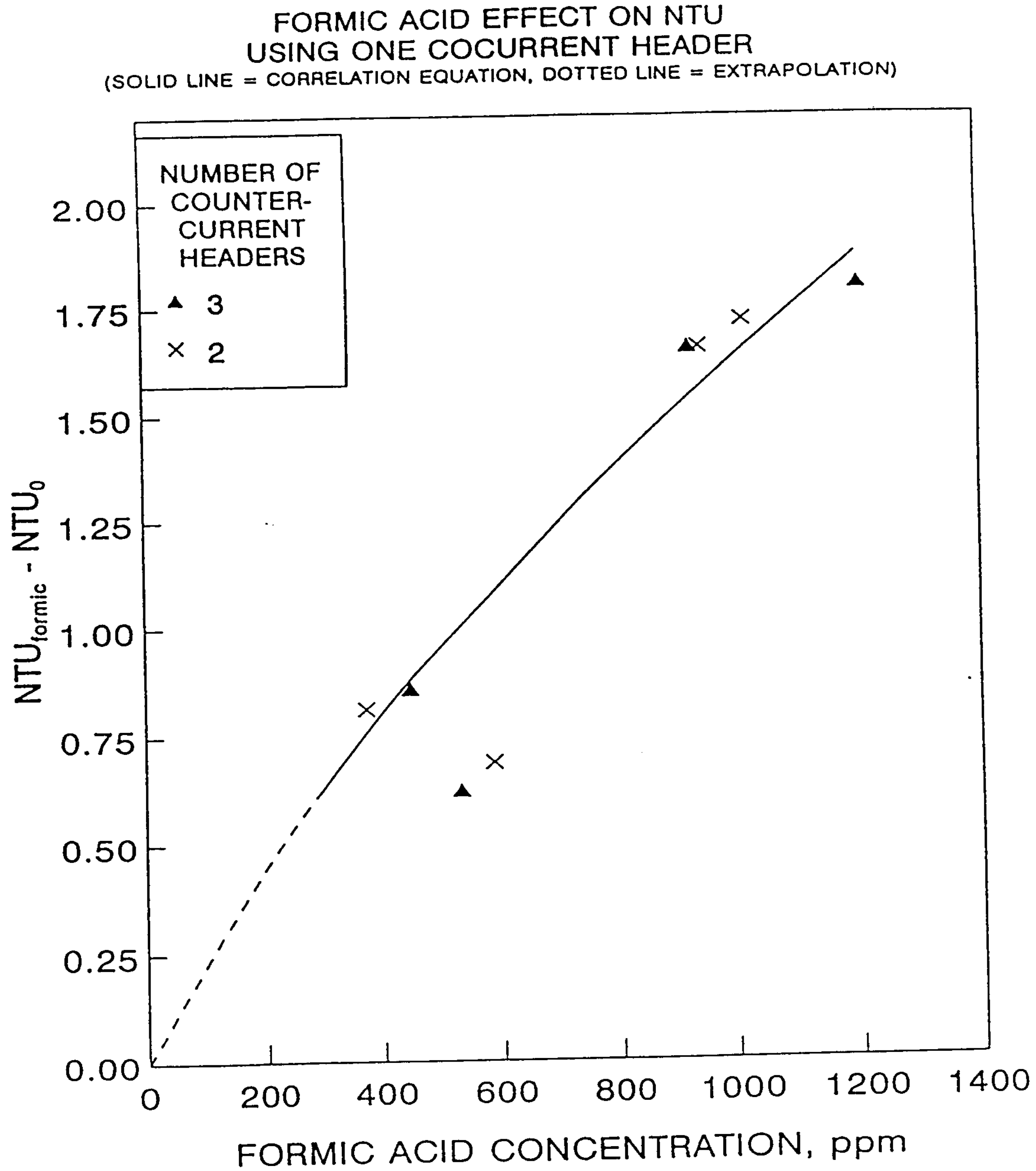


Figure 22. $NTU_{formic}$ minus $NTU_0$ vs Formic Acid Concentration, Tests Using One Cocurrent Header.

**FIGURE 4.8.2-23**

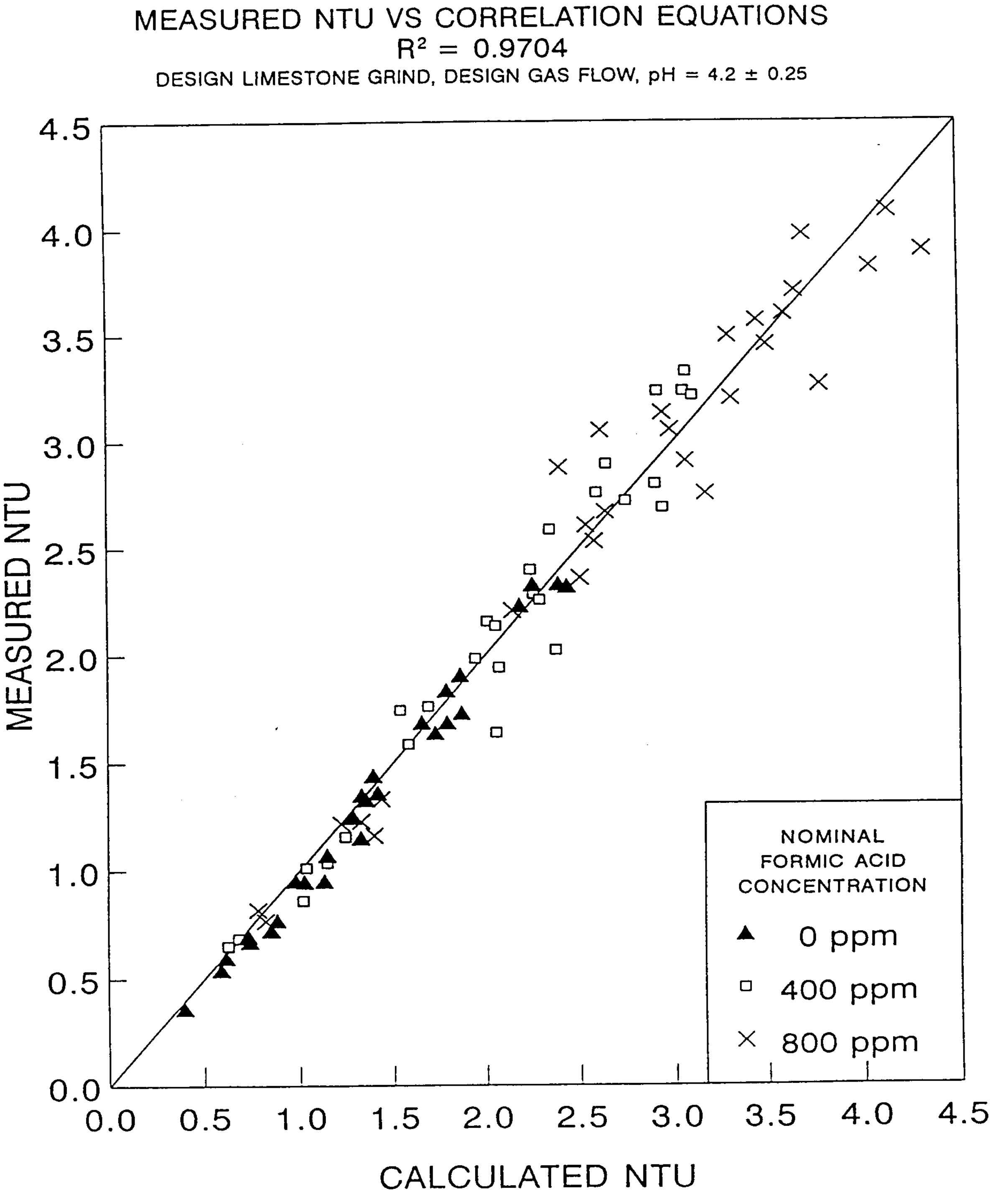


Figure 23. Parity Plot Showing the Measured vs Predicted NTU.

**FIGURE 4.8.2-24**

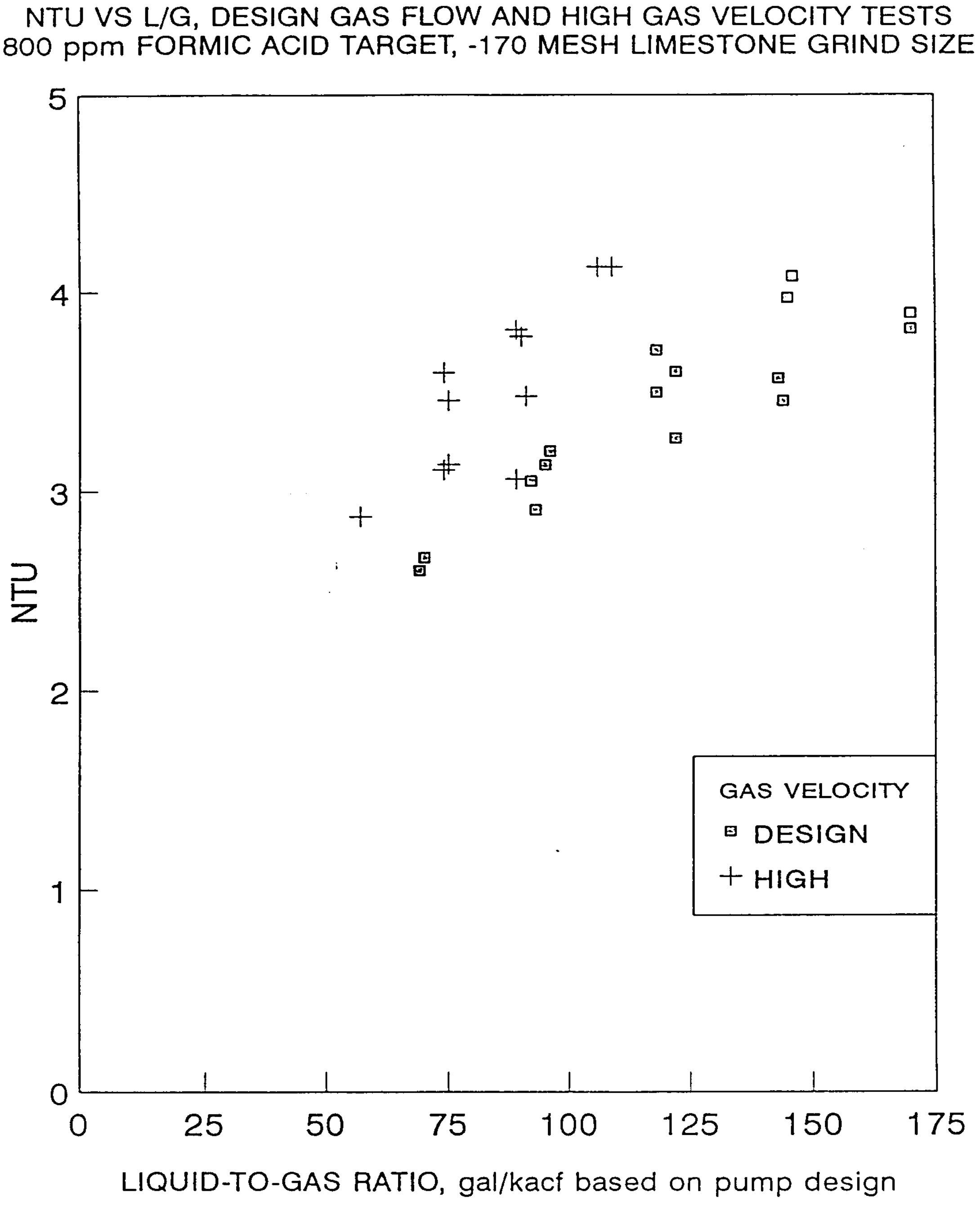


Figure 24. Number of Transfer Units vs Total L/G, Showing the Effect of Gas Velocity.

## FIGURE 4.8.2-25

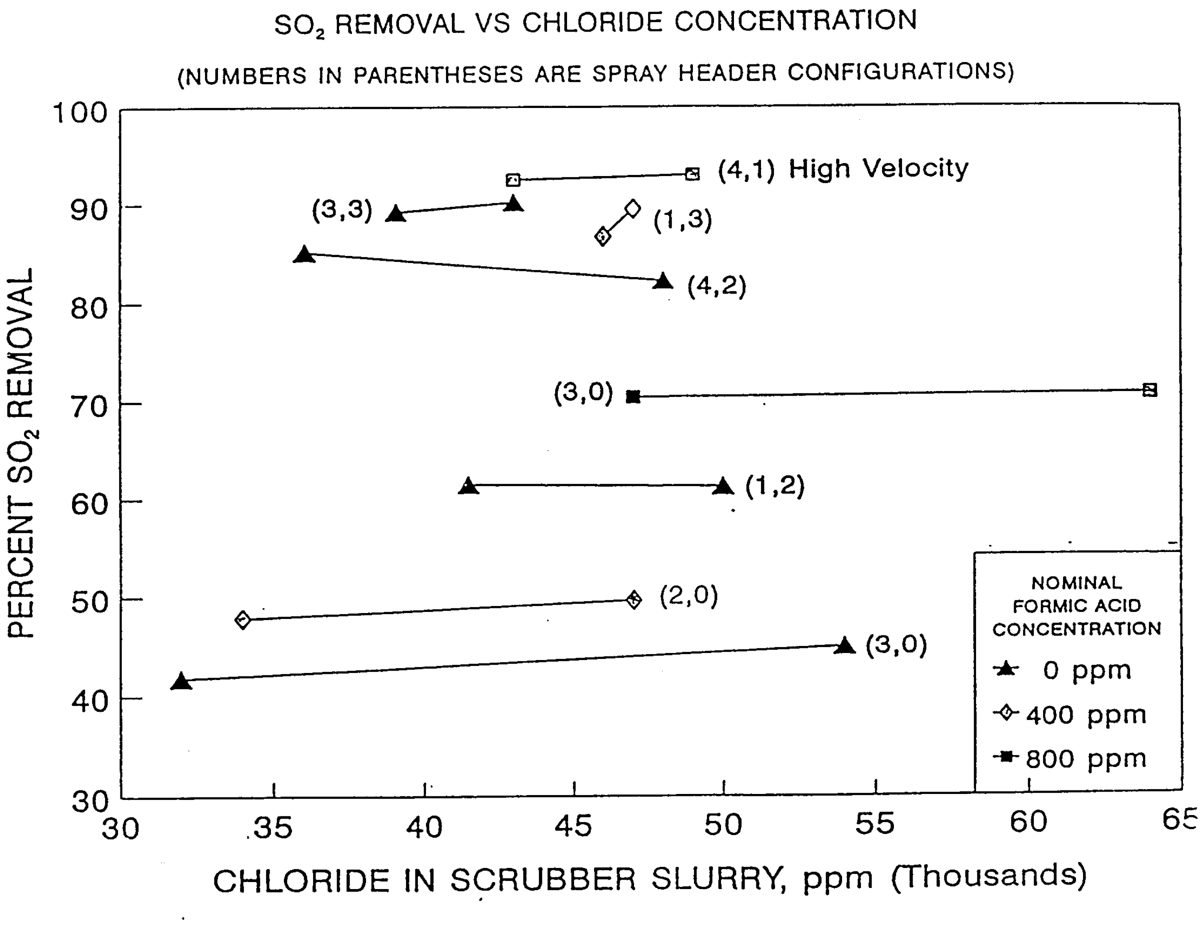


Figure 25. Effect of Chloride Concentration on $SO_2$ Removal in Repeat Tests.

## FIGURE 4.8.2-26

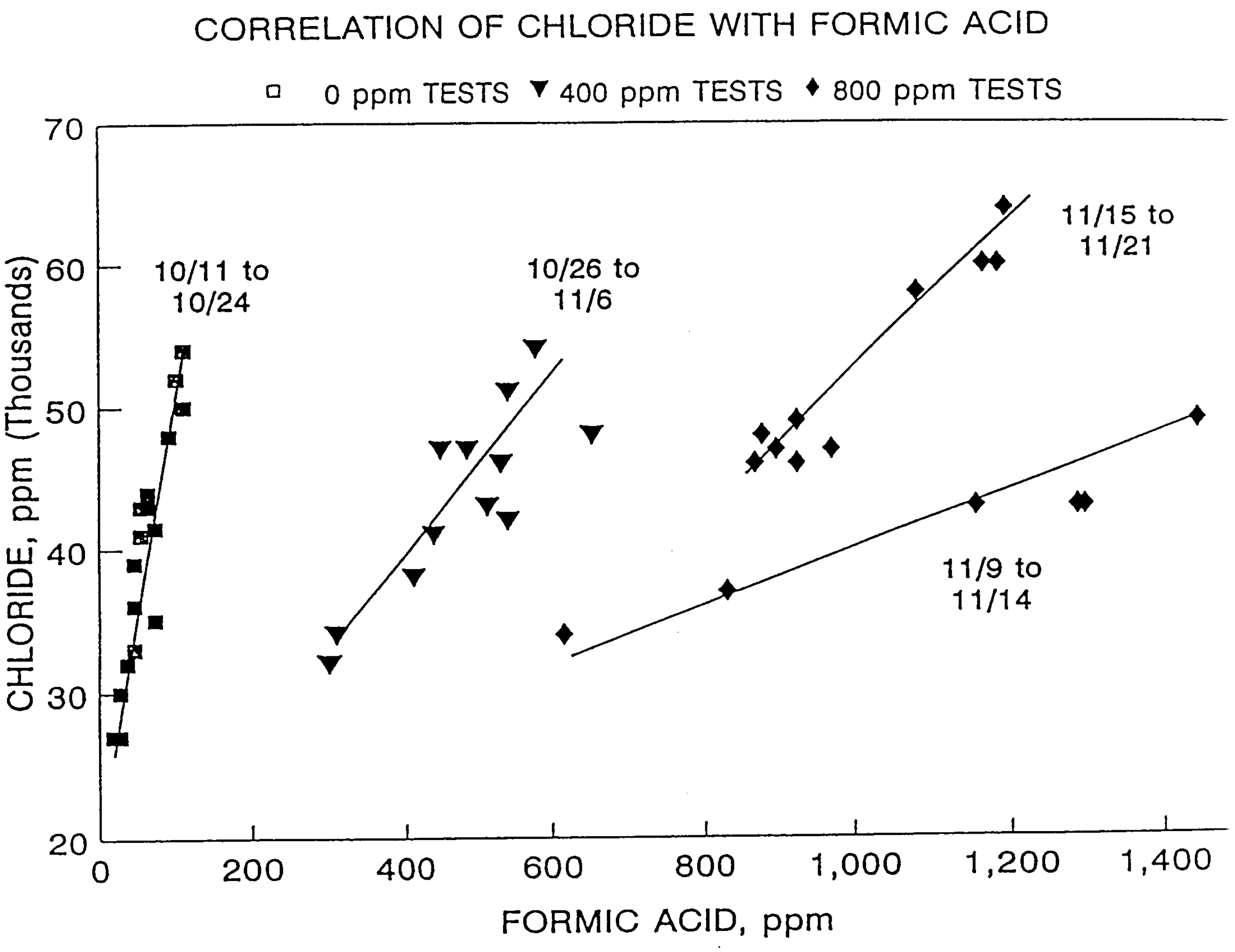


Figure 26. Chloride and Formic Acid Contents of Scrubber Slurry Samples.

# TABLE 4.8.2-1. TEST CONDITIONS AND RESULTS

| 1995 Data | Start Time | End Time | Test Nov | Unit 2 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | S02 Removal % | L/G, based on design pump flow gal/KACF | Number of Headers Operating | | Inlet/ Outlet ΔP In W.C. | Average pH | Inlet Gas | | | Coal S Based on Analyzers % | Stack Gas | | |
| | | | | | | Co-Current | Counter-Current | | | Measured Flow kACFM | Temperature °F | SO2 Conc. ppm | | Measured Flow kACFM | Calculated Flow kACFM | SO2 Conc. ppm | SO2 Emissions lb/MMBtu |
| 0 ppm Formic Acid, 90% - 325 mesh Limestone | | | | | | | | | | | | | | | | |
| 11-Oct | 12:00 | 18:00 | S-L-0-01 | 73.5% | 93 | 2 | 2 | 1.32 | 4.25 | 491.3 | 293.0 | 1010.6 | 1.62 | 416.0 | 416.8 | 245.83 | 0.63 |
| 11-Oct | 18:00 | 24:00 | S-L-0-02 | 85.2% | 142 | 4 | 2 | 1.42 | 4.21 | 495.0 | 288.7 | 979.8 | 1.60 | 421.4 | 421.4 | 133.94 | 0.35 |
| 12-Oct | 00:00 | 06:00 | S-L-0-03 | 90.2% | 167 | 4 | 3 | 1.84 | 4.20 | 492.9 | 255.0 | 904.0 | 1.57 | 420.9 | 420.9 | 87.22 | 0.23 |
| 12-Oct | 06:00 | 12:00 | S-L-0-04 | 78.3% | 91 | 1 | 3 | 1.80 | 4.21 | 499.4 | 289.8 | 987.1 | 1.02 | 424.7 | 424.7 | 215.08 | 0.56 |
| 12-Oct | 12:00 | 18:00 | S-L-0-05 | 81.5% | 117 | 3 | 2 | 1.42 | 4.22 | 500.1 | 290.0 | 1014.7 | 1.05 | 423.0 | 423.0 | 171.97 | 0.45 |
| 12-Oct | 18:00 | 24:00 | S-L-0-06 | 84.1% | 116 | 2 | 3 | 1.78 | 4.20 | 498.9 | 291.7 | 1007.2 | 1.65 | 423.6 | 423.6 | 147.45 | 0.39 |
| 13-Oct | 00:00 | 06:00 | S-L-0-07 | 61.4% | 92 | 3 | 1 | 0.98 | 4.20 | 498.8 | 259.4 | 973.8 | 1.59 | 422.6 | 422.6 | 345.73 | 0.90 |
| 13-Oct | 08:00 | 12:00 | S-L-0-08 | 68.4% | 119 | 4 | 1 | 0.85 | 4.19 | 485.5 | 288.2 | 297.0 | 1.00 | 413.5 | 413.5 | 290.10 | 0.75 |
| 13-Oct | 12:00 | 18:00 | S-L-0-09 | 49.1% | 98 | 4 | 0 | 0.37 | 4.24 | 492.9 | 304.1 | 1048.1 | 1.68 | 413.9 | 413.9 | 488.30 | 1.26 |
| l6-Oct | 20:00 | 24:00 | S-L-0-10 | 37.3% | 45 | 2 | 0 | 0.49 | 4.72 | 503.3 | 288.0 | 1042.7 | 1.72 | 428.4 | 428.4 | 602.00 | 1.59 |
| 17-Oct | 07:00 | 12:00 | S-L-0-11 | 01.3% | 69 | 1 | 2 | 1.32 | 4.22 | 490.2 | 280.3 | 1000.3 | 1.58 | 413.1 | 410.2 | 300.90 | 0.91 |
| 17-Oct | 12:00 | 16:00 | S-L-0-12 | 45.0% | 72 | 3 | 0 | 0.47 | 4.45 | 498.0 | 293.3 | 990.5 | 1.58 | 415.2 | 419.7 | 508.80 | 1.30 |
| 17- Oct | 16:00 | 20:00 | S-L-0-13 | 63.7% | 68 | 2 | 1 | 1.00 | 4.34 | 492.9 | 297.3 | 1020.7 | 1.80 | 415.8 | 414.9 | 433.78 | 1.09 |
| 13-Oct | 18:00 | 24:00 | S-L-0-14 | 89.3% | 141 | 3 | 3 | 1.78 | 4.20 | 501.8 | 299.5 | 954.7 | 1.54 | 422.9 | 422.9 | 93.93 | 0.24 |
| 17-Oct | 20:00 | 24:00 | S-L-0-15 | 50.3% | 98 | 4 | 0 | 0.50 | 4.22 | 502.8 | 291.3 | 1003.3 | 1.82 | 420.1 | 424.5 | 488.33 | 1.20 |
| 18-Oct | 00:00 | 04:00 | S-L-0-16 | 74.4% | 93 | 1 | 3 | 1.84 | 4.22 | 497.5 | 293.7 | 1012.0 | 1.82 | 418.6 | 419.7 | 239.95 | 0.62 |
| 14-Oct | 00:00 | 06:00 | S-L-0-17 | 71.3% | 116 | 4 | 1 | 0.98 | 4.10 | 502.3 | 297.1 | 959.5 | 1.55 | 424.4 | 424.4 | 252.43 | 0.65 |
| 18-Oct | 04:00 | 08:00 | S-L-0-18 | 65.8% | 93 | 3 | 1 | 1.02 | 4.22 | 498.1 | 293.8 | 1012.9 | 1.63 | 417.9 | 420.1 | 321.79 | 0.83 |
| 18-Oct | 08:00 | 12:00 | S-L-0-19 | 74.1% | 92 | 2 | 2 | 1.35 | 4.24 | 501.0 | 298.4 | 1025.8 | 1.65 | 422.6 | 421.2 | 243.62 | 0.63 |
| 14-Oct | 06:00 | 12:00 | S-L-0-20 | 90.3% | 165 | 4 | 3 | 1.86 | 4.22 | 504.7 | 294.7 | 979.0 | 1.80 | 427.3 | 427.3 | 87.30 | 0.23 |
| 18-Oct | 12:00 | 16:00 | S-L-0-21 | 30.3% | 45 | 2 | 0 | 0.44 | 4.23 | 604.1 | 303.0 | 1009.7 | 1.63 | 429.6 | 422.9 | 035.71 | 1.04 |
| 14-Oct | 12:00 | 18:00 | S-L-0-22 | 51.5% | 117 | 2 | 3 | 1.81 | 4.20 | 501.3 | 299.7 | 976.1 | 1.57 | 422.6 | 422.0 | 165.30 | 0.43 |
| 14-Oct | 15:00 | 24:00 | S-L-0-23 | 82.3% | 142 | 4 | 2 | 1.40 | 4.21 | 498.9 | 298.2 | 977.1 | 1.58 | 420.1 | 420.1 | 158.55 | 0.41 |
| 18-Oct | 16:00 | 20:00 | S-L-0-24 | 61.5% | 68 | 1 | 2 | 1.30 | 4.22 | 502.4 | 305.9 | 1014.8 | 1.62 | 430.7 | 420.9 | 349.21 | 0.89 |
| 18-Oct | 20:00 | 24:00 | S-L-0-25 | 41.8% | 69 | 3 | 0 | 0.47 | 4.22 | 498.4 | 208.9 | 1008.5 | 1.81 | 433.2 | 420.8 | 521.09 | 1.33 |
| 15-Oct | 00:00 | 06:00 | S-L-0-26 | 90.3% | 145 | 3 | 3 | 1.80 | 4.22 | 484.9 | 289.1 | 981.8 | 1.55 | 412.5 | 412.8 | 88.03 | 0.22 |
| 15-Oct | 06:00 | 12:00 | S-L-0-27 | 80.6% | 121 | 3 | 2 | 1.29 | 4.24 | 477.4 | 252.4 | 1087.4 | 1.67 | 408.7 | 408.7 | 191.09 | 0.48 |
| 19-Oct | 00:00 | 04:00 | S-L-0-28 | 51.5% | 66 | 2 | 1 | 1.00 | 4.22 | 501.2 | 290.0 | 983.6 | 1.59 | 429.3 | 422.9 | 431.08 | 1.11 |
| 0 ppm Formic Acid., 90% - 170 mesh Limestone | | | | | | | | | | | | | | | | |
| 24-Oct | 08:00 | 12:00 | S-L-0-29 | 88.2% | 171 | 4 | 3 | 1.76 | 4.10 | 480.4 | 298.3 | 962.1 | 1.45 | 411.8 | 405.1 | 102.84 | 0.25 |
| 24-Oct | 12:00 | 16:00 | S-L-0-30 | 78.7% | 119 | 3 | 2 | 1.36 | 4.08 | 483.0 | 296.5 | 964.9 | 1.48 | 413.0 | 407.7 | 186.87 | 0.46 |
| 24-Oct | 16:00 | 20:00 | S-L-0-31 | 49.2% | 68 | 2 | 1 | 0.96 | 4.08 | 486.6 | 297.3 | 946.6 | 1.46 | 416.0 | 410.5 | 435.99 | 1.08 |
| 0 ppm Formic Acid, 90% -325 mesh LS, 5.0 pH | | | | | | | | | | | | | | | | |
| 19-Oct | 12:00 | 16:00 | S-L-0-1A | 35.4% | 45 | 2 | 0 | 0.43 | 4.96 | 500.4 | 300.3 | 969.4 | 1.55 | 427.7 | 420.9 | 565.21 | 1.45 |
| 19-Oct | 16:00 | 20:00 | S-L-0-2A | 50.5% | 69 | 3 | 0 | 0.51 | 5.02 | 501.7 | 303.0 | 973.6 | 1.5( | 431.2 | 421.6 | 430.88 | 1.10 |
| 19-Oct | 20:00 | 24:00 | S-L-0-3A | 55.3% | 94 | 4 | 0 | 0.45 | 5.00 | 503.2 | 299.8 | 977.7 | 1.58 | 428.0 | 423.1 | 398.85 | 1.02 |
| 20-Oct | 00.00 | 04:00 | S-L-0-4A | 94.4% | 103 | 4 | 3 | 1.78 | 5.05 | 499.6 | 301.0 | 990.0 | 1.58 | 430.2 | 420.3 | 49.98 | 0.13 |
| 20-Oct | 04:00 | 08:00 | S-L-0-5A | 83.1% | 91 | 2 | 2 | 1.33 | 4.95 | 498.5 | 300.5 | 987.8 | 1.58 | 427.4 | 419.5 | 150.71 | 0.39 |
| 20-Oct | 08:00 | 12:00 | S-L-0-6A | 80.3% | 92 | 3 | 1 | 1.04 | 5.02 | 501.4 | 300.4 | 1041.8 | 1.87 | 421.7 | 420.8 | 188.40 | 0.48 |

# TABLE 4.8.2-1.  TEST CONDITIONS AND RESULTS

| 1995 Data | Start Time | End Time | Test Nov | Unit 2 | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | S02 Removal % | L/G, based on design pump flow gal/KACF | Number of Headers Operating | | Inlet/ Outlet ΔP In W.C. | Average pH | Inlet Gas | | | Coal S Based on Analyzers % | Stack Gas | | | |
| | | | | | | Co-Current | Counter-Current | | | Measured Flow kACFM | Temperature °F | SO2 Conc. ppm | | Measured Flow kACFM | Calculated Flow kACFM | SO2 Conc. ppm | SO2 Emissions lb/MMBtu |
| 400 ppm Formic Acid 90% - 170 mesh Limestone | | | | | | | | | | | | | | | | | |
| 26-Oct | 12:00 | 16:00 | S-L-1-01 | 63.7% | 72 | 3 | 0 | 0.48 | 4.10 | 477.8 | 294.6 | 983.6 | 1.49 | 413.5 | 404.5 | 320.63 | 0.78 |
| 28-Oct | 16:00 | 20:00 | S-L-1-02 | 89.6% | 94 | 1 | 3 | 1.72 | 4.10 | 479.0 | 297.4 | 984.1 | 1.49 | 414.1 | 404.7 | 92.13 | 0.22 |
| 20-Oct | 20:00 | 24:00 | S-L-1-03 | 88.3% | 95 | 3 | 1 | 0.99 | 4.09 | 475.7 | 299.4 | 1004.2 | 1.51 | 409.7 | 401.1 | 123.72 | 0.30 |
| 27-Oct | 00:00 | 04:00 | S-L-1-04 | 79.8% | 67 | 2 | 1 | 0.98 | 4.11 | 480.7 | 298.7 | 988.2 | 1.53 | 420.5 | 411.3 | 151.15 | 0.45 |
| 27-Oct | 04:00 | 08:00 | S-L-1-05 | 89.8% | 92 | 2 | 2 | 1.31 | 4.10 | 484.0 | 294.3 | 988.7 | 1.51 | 419.7 | 410.1 | 90.26 | 0.22 |
| 27-Oct | 08:00 | 12:00 | S-L-1-06 | 85.7% | 116 | 4 | 1 | 0.99 | 4.12 | 489.7 | 298.0 | 1007.9 | 1.55 | 423.8 | 414.2 | 129.45 | 0.32 |
| 27-Oct | 12:00 | 10:00 | S-L-1-07 | 80.8% | 67 | 1 | 2 | 1.35 | 4.12 | 488.0 | 207.8 | 1007.9 | 1.58 | 421.3 | 412.0 | 175.12 | 0.43 |
| 27-Oct | 18:00 | 20:00 | S-L-1-08 | 93.9% | 142 | 4 | 2 | 1.41 | 4.13 | 488.8 | 298.0 | 1034.9 | 1.60 | 421.9 | 412.4 | 58.27 | 0.14 |
| 27-Oct | 20:00 | 24:00 | S-L-1-09 | 93.2% | 117 | 2 | 3 | 1.70 | 4.12 | 490.1 | 302.7 | 1008.8 | 1.58 | 420.0 | 411.8 | 61.52 | 0.15 |
| 30-Oct | 18:00 | 20:00 | S-L-1-10 | 92.5% | 117 | 3 | 2 | 1.49 | 4.18 | 452.8 | 297.1 | 1137.9 | 1.74 | 422.5 | 408.7 | 75.83 | 0.19 |
| 30-Oct | 20:00 | 24:00 | S-L-1-11 | 90.1% | 166 | 4 | 3 | 1.84 | 4.13 | 481.4 | 290.5 | 1029.0 | 1.57 | 422.3 | 407.9 | 35.75 | 0.09 |
| 30-Oct | 08:00 | 12:00 | S-L-1-12 | 47.9% | 45 | 2 | 0 | 0.40 | 4.17 | 489.0 | 294.7 | 1097.2 | 1.71 | 427.0 | 414.0 | 509.26 | 1.27 |
| 31-Oct | 00:00 | 04:00 | S-L-1-13 | 98.1% | 141 | 3 | 3 | 1.83 | 4.09 | 483.1 | 298.9 | 953.0 | 1.40 | 423.3 | 408.5 | 33.02 | 0.08 |
| 30-Oct | 12:00 | 18:00 | S-L-I-14 | 64.5% | 97 | 4 | 0 | 0.40 | 4.18 | 478.8 | 294.8 | 1164.5 | 1.77 | 415.7 | 405.8 | 368.80 | 0.90 |
| 31-Oct | 04:00 | 08:00 | S-L-1-15 | 82.9% | 88 | 1 | 2 | 1.30 | 4.07 | 477.9 | 297.3 | 930.5 | 1.43 | 414.0 | 404.1 | 142.48 | 0.35 |
| 31-Oct | 08:00 | 12:00 | S-L-1-16 | 93.7% | 119 | 3 | 2 | 1.39 | 4.08 | 480.7 | 297.5 | 904.0 | 1.39 | 415.0 | 406.0 | 51.32 | 0.13 |
| 31-Oct | 12:00 | 16:00 | S-L-1-17 | 94.5% | 144 | 4 | 2 | 1.30 | 4.08 | 481.6 | 298.2 | 909.9 | 1.40 | 418.3 | 406.5 | 45.05 | 0.11 |
| 31-Oct | 10:00 | 20:00 | S-L-1-18 | 82.6% | 68 | 2 | 1 | 0.97 | 4.06 | 485.2 | 299.0 | 898.0 | 1.39 | 417.2 | 409.1 | 140.79 | 0.35 |
| 31-Oct | 20:00 | 00:00 | S-L-1-19 | 68.6% | 97 | 4 | 0 | 0.52 | 4.08 | 484.5 | 298.9 | 902.6 | 1.41 | 417.4 | 408.6 | 254.62 | 0.84 |
| 01-Nov | 00:00 | 04:00 | S-L-1-20 | 96.0% | 142 | 3 | 3 | 1.94 | 4.07 | 489.2 | 299.9 | 907.2 | 1.42 | 420.5 | 412.1 | 32.88 | 0.08 |
| 01-Nov | 04:00 | 08:00 | S-L-1-21 | 93.4% | 117 | 2 | 3 | 1.80 | 4.07 | 485.7 | 300.3 | 929.8 | 1.44 | 420.0 | 409.5 | 54.45 | 0.14 |
| 01-Nov | 08:00 | 12:00 | S-L-1-22 | 57.8% | 89 | 3 | 0 | 0.57 | 4.07 | 502.7 | 308.2 | 898.0 | 1.43 | 435.9 | 421.8 | 334.91 | 0.85 |
| 01-Nov | 12:00 | 16:00 | S-L-1-23 | 80.8% | 89 | 1 | 3 | 1.94 | 4.07 | 508.2 | 310.8 | 888.6 | 1.42 | 438.4 | 424.3 | 103.86 | 0.27 |
| 01-Nov | 16:00 | 20:00 | S-L-1-24 | 90.9% | 90 | 2 | 2 | 1.48 | 4.05 | 499.7 | 309.3 | 892.5 | 1.42 | 432.1 | 418.1 | 71.53 | 0.18 |
| 01-Nov | 20:00 | 24:00 | S-L-1-25 | 88.5% | 90 | 3 | 1 | 1.13 | 4.06 | 497.5 | 307.5 | 891.2 | 1.42 | 428.9 | 416.7 | 91.22 | 0.23 |
| 02-Nov | 00:00 | 04:00 | S-L-1-26 | 49.7% | 45 | 2 | 0 | 0.51 | 4.06 | 499.1 | 309.4 | 901.2 | 1.43 | 428.9 | 417.2 | 402.60 | 1.02 |
| 02-Nov | 04:00 | 08:00 | S-L-1-27 | 88.2% | 115 | 4 | 1 | 1.07 | 4.05 | 499.7 | 311.3 | 938.8 | 1.49 | 427.8 | 418.8 | 98.38 | 0.25 |
| 02-Nov | 08:00 | 12:00 | S-L-1-28 | 96.4% | 168 | 4 | 3 | 1.95 | 4.10 | 495.7 | 312.6 | 974.0 | 1.53 | 424.4 | 413.1 | 30.99 | 0.08 |
| 400 ppm Formic Acid 90%  - 325 mesh Limestone | | | | | | | | | | | | | | | | | |
| 06-Nov | 08:00 | 12:00 | S-L-1-29 | 96.3% | 116 | 3 | 2 | 1.52 | 4.11 | 492.4 | 298.3 | 985.0 | 1.56 | 425.4 | 415.0 | 32.25 | 0.08 |
| 08-Nov | 12:00 | 1600 | S-L-1-30 | 97.4% | 165 | 4 | 3 | 1.93 | 4.10 | 497.1 | 301.8 | 952.1 | 1.51 | 425.5 | 417.8 | 22.60 | 0.06 |
| 06-Nov | 16:00 | 20:00 | S-L-1-31 | 88.3% | 87 | 2 | 1 | 1.05 | 4.08 | 492.1 | 300.5 | 958.0 | 1.53 | 424.7 | 414.6 | 99.85 | 0.25 |

# TABLE 4.8.2-1. TEST CONDITIONS AND RESULTS

| | | | | Unit 2 | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Number of Headers Operating | | | | Inlet Gas | | | | Stack Gas | | | |
| 1995 Data | Start Time | End Time | Test no. | S02 Removal % | L/G, based on design pump flow gal/KACF | Co-Current | Counter-Current | Inlet/ Outlet $\Delta P$ In W.C. | Average pH | Measured Flow kACFM | Temperature $^{o}$F | SO2 Conc. ppm | Coal S Based on Analyzers % | Measured Flow kACFM | Calculated Flow kACFM | SO2 Conc. ppm | SO2 Emissions lb/MMBtu |
| 800 ppm Formic Acid 90% - 170 mash Limestone | | | | | | | | | | | | | | | | | |
| 15-Nov | 20:00 | 24:00 | S-L-2-01 | 73.6% | 97 | 4 | 0 | 0.40 | 4.07 | 490.3 | 296.7 | 913.8 | 1.44 | 417.6 | 413.5 | 219.35 | 0.55 |
| 16-Nov | 00:00 | 04:00 | S-L-2-02 | 70.4% | 71 | 3 | 0 | 0.45 | 4.07 | 492.0 | 295.7 | 899.4 | 1.42 | 420.3 | 415.4 | 241.87 | 0.61 |
| 16-Nov | 04:00 | 08:00 | S-L-2-03 | 98.1% | 145 | 3 | 3 | 1.71 | 4.06 | 488.2 | 295.0 | 908.1 | 1.42 | 411.1 | 409.9 | 15.62 | 0.04 |
| 16-Nov | 08:00 | 12:00 | S-L-2-04 | 94.4% | 94 | 3 | 1 | 0.98 | 4.09 | 487.0 | 293.2 | 910.0 | 1.43 | 411.9 | 412.1 | 47.22 | 0.12 |
| 16-Nov | 12:00 | 16:00 | S-L-2-05 | 98.2% | 122 | 3 | 2 | 1.37 | 4.19 | 482.9 | 293.7 | 900.8 | 1.40 | 405.4 | 407.4 | 31.85 | 0.08 |
| 16-Nov | 16:00 | 20:00 | S-L-2-08 | 92.6% | 69 | 1 | 2 | 1.33 | 4.05 | 491.9 | 294.5 | 592.1 | 1.39 | 412.7 | 414.0 | 61.03 | 0.15 |
| 16-Nov | 20:00 | 24:00 | S-L-2-07 | 97.8% | 170 | 4 | 3 | 1.81 | 4.05 | 490.1 | 294.0 | 890.7 | 1.39 | 413.8 | 413.7 | 17.95 | 0.04 |
| 17-Nov | 04:00 | 08:00 | S-L-2-08 | 97.0% | 118 | 2 | 3 | 1.75 | 4.06 | 490.4 | 295.5 | 908.6 | 1.41 | 418.7 | 413.8 | 25.13 | 0.06 |
| 17-Nov | 08:00 | 12:00 | S-L-2-09 | 55.9% | 47 | 2 | 0 | 0.34 | 4.04 | 482.1 | 298.1 | 884.3 | 1.34 | 411.2 | 406.9 | 354.68 | 0.88 |
| 17-Nov | 12:00 | 18:00 | S-L-2-10 | 92.1% | 118 | 4 | 1 | 0.92 | 4.05 | 487.8 | 299.0 | 878.4 | 1.35 | 416.1 | 410.8 | d3.28 | 0.18 |
| 17-Nov | 16:00 | 20:00 | S-L-2-11 | 89.0% | 69 | 2 | 1 | 0.85 | 4.04 | 482.7 | 297.5 | 870.1 | 1.34 | 411.5 | 407.0 | 88.99 | 0.21 |
| 17-Nov | 20:00 | 24:00 | S-L-2- 2 | 95.8% | 95 | 2 | 2 | 1.31 | 4.03 | 480.8 | 298.7 | 870.6 | 1.33 | 410.4 | 404.9 | 34.41 | 0.08 |
| 18-Nov | 08:00 | 12:00 | S-L-2-13 | 98.8% | 144 | 4 | 2 | 1.35 | 4.05 | 488.0 | 298.9 | 870.6 | 1.35 | 416.6 | 412.1 | 24.97 | 0.06 |
| 18-Nov | 12:00 | 16:00 | S-L-2-14 | 95.3% | 92 | 1 | 3 | 1.77 | 4.08 | 491.2 | 296.3 | 878.8 | 1.38 | 419.5 | 414.5 | 37.58 | 0.09 |
| 18-Nov | 18:00 | 20:00 | S-L-2-15 | 53.6% | 47 | 2 | 0 | 0.34 | 4.05 | 489.8 | 297.3 | 867.4 | 1.35 | 417.2 | 412.9 | 388.43 | 0.91 |
| 18-Nov | 20:00 | 24:00 | S-L-2-16 | 94.8% | 93 | 2 | 2 | 1.31 | 4.05 | 493.7 | 297.8 | 873.3 | 1.36 | 417.5 | 415.6 | 43.54 | 0.11 |
| 19-Nov | 16:00 | 20:00 | S-L-2-17 | 68.8% | 98 | 4 | 0 | 0.30 | 4.04 | 490.0 | 298.4 | 857.3 | 1.34 | 420.5 | 413.2 | 241.57 | 0.60 |
| 19-Nov | 20:00 | 24:00 | S-L-2-18 | 97.2% | 143 | 4 | 2 | 1.33 | 4.04 | 487.1 | 297.0 | 863.2 | 1.35 | 418.1 | 411.2 | 21.93 | 0.05 |
| 20-Nov | 08:00 | 12:00 | S-L-2-19 | 95.3% | 96 | 3 | 1 | 0.97 | 4.04 | 477.7 | 301.7 | 879.3 | 1.35 | 406.1 | 401.2 | 37.80 | 0.09 |
| 20-Nov | 12:00 | 16:00 | S-L-2-20 | 93.1% | 70 | 1 | 2 | 1.32 | 4.03 | 480.5 | 303.0 | 873.5 | 1.35 | 406.0 | 402.8 | 55.07 | 0.14 |
| 20-Nov | 16:00 | 20:00 | S-L-2-21 | 98.0% | 170 | 4 | 3 | 1.75 | 4.04 | 487.5 | 305.1 | 864.2 | 1.34 | 413.0 | 408.1 | 15.83 | 0.04 |
| 20-Nov | 20:00 | 24:00 | S-L-2-22 | 98.3% | 148 | 3 | 3 | 1.70 | 4.03 | 484.6 | 307.5 | 877.9 | 1.35 | 410.0 | 404.9 | 13.35 | 0.03 |
| 21-Nov | 00:00 | 04:00 | S-L-2-23 | 97.6% | 118 | 2 | 3 | 1.77 | 4.04 | 495.8 | 307.9 | 850.9 | 1.34 | 418.2 | 413.8 | 18.84 | 0.05 |
| 21-Nov | 04:00 | 08:00 | S-L-2-24 | 93.7% | 122 | 4 | 1 | 0.89 | 4.05 | 478.9 | 303.9 | 872.4 | 1.33 | 403.8 | 401.1 | 50.40 | 0.12 |
| 21-Nov | 08:00 | 12:00 | S-L-2-25 | 97.3% | 122 | 3 | 2 | 1.26 | 4.04 | 481.0 | 305.2 | 878.1 | 1.34 | 403.2 | 402.1 | 21.83 | 0.05 |
| 21-Nov | 12:00 | 16:00 | S-L-2-26 | 70.7% | 73 | 3 | 0 | 0.40 | 4.02 | 485.1 | 305.7 | 845.8 | 1.31 | 408.8 | 405.6 | 225.13 | 0.56 |
| 21-Nov | 18:00 | 20:00 | S-L-2-27 | 95.9% | 96 | 1 | 3 | 1.69 | 4.03 | 477.4 | 305.0 | 869.2 | 1.34 | 402.9 | 399.8 | 32.07 | 0.08 |
| 21-Nov | 20:00 | 24:00 | S-L-2-28 | 90.8% | 70 | 2 | 1 | 0.89 | 4.03 | 477.4 | 304.7 | 863.2 | 1.33 | 403.1 | 399.7 | 74.06 | 0.18 |
| 800 ppm Formic Acid 90% -325 mesh Limestone | | | | | | | | | | | | | | | | | |
| 09-Nov | 08:00 | 12:00 | S-L-2-29 | 98.7% | 107 | 4 | 3 | 1.94 | 4.08 | 480.1 | 295.0 | 960.3 | 1.50 | 421.1 | 407.3 | 10.73 | 0.03 |
| 09-Nov | 12:00 | 10:00 | S-L-2-30 | 97.4% | 117 | 3 | 2 | 1.54 | 4.08 | 480.8 | 294.7 | 928.7 | 1.45 | 420.3 | 407.8 | 21.35 | 0.05 |
| 09-Nov | 16:00 | 20:00 | S-L-2-31 | 92.8% | 50 | 2 | 1 | 1.05 | 4.07 | 486.4 | 291.8 | 92B.7 | 1.48 | 426.2 | 413.6 | 61.00 | 0.15 |
| High Velocity Tests, 800 ppm Formic Acid | | | | | | | | | | | | | | | | | |
| 13-Nov | 08:00 | 12:00 | H-L-2-00 | 98.4% | 109 | 4 | 3 | 3.70 | 4.40 | 689.8 | 275.6 | 920.9 | 1.56 | 645.9 | 624.2 | 12.16 | 0.03 |
| 13-Nov | 12:00 | 16:00 | H-L-2-01 | 90.8% | 50 | 3 | 1 | 2.78 | 4.22 | 753.0 | 285.6 | 972.2 | 1.60 | 698.2 | 673.5 | 71.74 | 0.19 |
| 13-Nov | 16:00 | 20:00 | H-L-2-02 | 96.8% | 75 | 3 | 2 | 3.09 | 4.32 | 699.3 | 277.3 | 934.7 | 1.56 | 654.0 | 632.5 | 24.20 | 0.06 |
| 13-Nov | 20:00 | 24:00 | H-L-2-03 | 93.1% | 75 | 4 | 1 | 2.36 | 4.26 | 706.2 | 274.4 | 924.6 | 1.57 | 657.3 | 639.7 | 53.12 | 0.14 |
| 14-Nov | 00:00 | 04:00 | H-L-2-04 | 98.4% | 106 | 4 | 3 | 3.74 | 4.16 | 718.5 | 274.9 | 904.0 | 1.54 | 663.7 | 649.9 | 12.41 | 0.03 |
| 14-Nov | 04:00 | 08:00 | H-L-2-05 | 97.3% | 74 | 2 | 3 | 3.71 | 4.20 | 716.9 | 278.2 | 868.9 | 1.52 | 683.2 | 647.8 | 20.08 | 0.05 |
| 14-Nov | 08:00 | 12:00 | H-L-2-06 | 92.6% | 74 | 4 | 1 | 2.43 | 4.31 | 719.1 | 276.0 | 877.9 | 1.48 | 883.7 | 650.0 | 53.63 | 0.14 |
| 14-Nov | 12:00 | 16:00 | H-L-2-07 | 98.9% | 91 | 4 | 2 | 3.10 | 4.30 | 715.2 | 276.5 | 852.7 | 1.43 | 658.5 | 645.7 | 21.39 | 0.08 |
| 14-Nov | 16:00 | 20:00 | H-L-2-08 | 97.7% | go | 3 | 3 | 3.93 | 4.03 | 721.1 | 277.8 | 824.8 | 1.39 | 660.9 | 650.0 | 15.43 | 0.04 |
| 14-Nov | 20:00 | 24:00 | H-L-2-09 | 95.7% | 75 | 3 | 2 | 3.32 | 3.97 | 721.4 | 273.7 | 808.3 | 1.38 | 658.8 | 652.9 | 29.04 | 0.08 |
| 15-Nov | 00:00 | 04:00 | H-L-2-10 | 95.5% | 74 | 2 | 3 | 3.68 | 4.03 | 730.7 | 274.0 | 787.3 | 1.34 | 666.6 | 660.8 | 29.33 | 0.08 |
| 15-Nov | 04:00 | 08:00 | H-L-2-11 | 95.3% | 89 | 4 | 2 | 3.28 | 4.22 | 734.2 | 272.9 | 785.4 | 1.35 | 674.3 | 665.4 | 30.45 | 0.08 |
| 15-Nov | 08:00 | 12:00 | H-L-2-12 | 97.8% | 89 | 3 | 3 | 4.04 | 4.21 | 734.7 | 275.5 | 829.8 | 1.42 | 675.2 | 664.2 | 14.94 | 0.04 |
| 15-Nov | 12:00 | 10:00 | H-L-2-13 | 94.4% | 57 | 2 | 2 | 3.13 | 4.36 | 735.1 | 275.9 | 852.7 | 1.46 | 675.8 | 664.3 | 38.89 | 0.11 |

# TABLE 4.8.2-1. TEST CONDITIONS AND RESULTS

| 1995 Data | Start Time | End Time | Test Nov | Average Coal Flow ton/hr | Average Gross Load MW | Station Service Load MW | Average Net Load MW | Average Opacity % | Average Nov Emissions lb/MMBTU | Average O2 % | Baro-metric Pressure In Hg | Outdoor Temper-ature °F | Total Nov of Headers Unit 2 | Unit 2 Mass Transfer Units NTU | KgaPV (=NTU*G) (kmol/hr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 ppm Formic Acid, 90% -325 mesh Limestone | | | | | | | | | | | | | | | |
| 11-Oct | 12:00 | 18:00 | S-L-0-01 | 53.40 | 157.0 | 9.78 | 148.1 | 3.06 | 0.373 | 3.66 | NA | NA | 4 | 1.330 | 71.35 |
| 11-Oct | 18:00 | 24:00 | S-L-0-02 | 53.39 | 158.9 | 10.15 | 148.7 | 3.13 | 0.344 | 3.80 | NA | NA | 6 | 1.908 | 103.75 |
| 12-Oct | 00:00 | 06:00 | S-L-0-03 | 53.40 | 157.1 | 11.17 | 145.9 | 3.35 | 0.358 | 3.81 | NA | NA | 7 | 2.322 | 128.34 |
| 12-Oct | 06:00 | 12:00 | S-L-0-04 | 53.40 | 156.6 | 10.14 | 148.4 | 3.50 | 0.399 | 3.78 | NA | NA | 4 | 1.442 | 78.97 |
| 12-Oct | 12:00 | 18:00 | S-L-0-05 | 53.40 | 158.2 | 10.17 | 148.0 | 2.57 | 0.383 | 3.62 | NA | NA | 5 | 1.690 | 91.94 |
| 12-Oct | 18:00 | 24:00 | S-L-0-06 | 53.41 | 158.1 | 9.93 | 148.1 | 2.03 | 0.383 | 3.62 | NA | NA | 5 | 1.838 | 100.34 |
| 13-Oct | 00:00 | 06:00 | S-L-0-07 | 63.40 | 157.9 | 9.77 | 148.1 | 2.75 | 0.393 | 3.63 | NA | NA | 4 | 0.953 | 51.07 |
| 13-Oct | 06:00 | 12:00 | S-L-0-08 | 53.10 | 158.6 | 10.26 | 146.3 | 3.57 | 0.422 | 3.62 | NA | NA | 5 | 1.152 | 61.50 |
| 13-Oct | 12:00 | 18:00 | S-L-0-09 | 52.79 | 158.3 | 9.87 | 146.4 | 1.87 | 0.428 | 3.72 | NA | NA | 4 | 0.575 | 35.78 |
| 16-Oct | 20:00 | 24:00 | S-L-0-l0 | 53.65 | 158.2 | 9.94 | 146.3 | 1.96 | 0.553 | 4.10 | NA | NA | 2 | 0.487 | 25.83 |
| 17-Oct | 07:00 | 12:00 | S-L-0-11 | 54.60 | 158.0 | 9.54 | 148.4 | 3.31 | 0.501 | 3.99 | 29.97 | 45.2 | 3 | 0.950 | 51.34 |
| 17-Oct | 12:00 | 16:00 | S-L- 012 | 54.80 | 157.8 | 9.59 | 148.1 | 1.97 | 0.559 | 3.98 | 30.03 | 52.0 | 3 | 0.599 | 32.54 |
| 17-Oct | 16:00 | 20:00 | S-L-0-13 | 54.59 | 158.6 | 9.68 | 148.9 | 1.28 | 0.560 | 4.08 | 30.03 | 57.8 | 3 | 0.771 | 41.28 |
| 13-Oct | 18:00 | 24:00 | S-L-0-14 | 53.82 | 158.2 | 11.04 | 147.1 | 3.10 | 0.423 | 3.79 | NA | NA | 6 | 2.232 | 121.25 |
| 17-Oct | 20:00 | 24:00 | S-L-0-15 | 54.60 | 159.1 | 10.67 | 148.3 | 0.98 | 0.557 | 4.10 | 30.03 | 52.9 | 4 | 0.699 | 38.48 |
| 18-Oct | 00:00 | 04:00 | S-L-0-16 | 54.18 | 158.0 | 10.25 | 147.7 | 0.76 | 0.558 | 4.10 | 29.86 | 52.7 | 4 | 1.362 | 73.90 |
| 14-Oct | 00:00 | 06:00 | S-L-0-17 | 54.00 | 158.9 | 10.32 | 148.5 | 3.39 | 0.391 | 3.72 | NA | NA | 5 | 1.249 | 88.18 |
| 18-Oct | 04:00 | 08:00 | S-L-0-18 | 54.00 | 157.8 | 9.96 | 147.8 | 1.94 | 0.557 | 4.10 | 29.88 | 58.4 | 4 | 1.072 | 58.27 |
| 18-Oct | 08:00 | 12:00 | S-L-0-19 | 54.00 | 158.3 | 9.92 | 148.4 | 2.86 | 0.658 | 4.11 | 29.86 | 01.2 | 4 | 1.351 | 73.42 |
| 14-Oct | 08:00 | 12:00 | S-L-0-20 | 54.01 | 158.5 | 10.58 | 147.9 | 2.94 | 0.390 | 3.80 | NA | NA | 7 | 2.333 | 128.34 |
| 18-Oct | 12:00 | 16:00 | S-L-0-21 | 53.99 | 157.8 | 9.47 | 148.3 | 2.05 | 0.569 | 4.10 | 29.88 | 70.8 | 2 | 0.360 | 19.58 |
| 14-Oct | 12:00 | 18:00 | S-L-0-22 | 54.00 | 158.0 | 10.12 | 148.4 | 2.89 | 0.398 | 3.50 | NA | NA | 5 | 1.689 | 91.85 |
| 14-Oct | 18:00 | 24:00 | S-L-0-23 | 54.01 | 158.7 | 10.44 | 148.2 | 2.48 | 0.395 | 3.57 | NA | NA | 6 | 1.733 | 93.05 |
| 18-Oct | 18:00 | 20:00 | S-L-0-24 | 54.00 | 158.5 | 9.69 | 148.8 | 3.23 | 0.580 | 4.10 | 29.88 | 70.2 | 3 | 0.955 | 51.51 |
| 18-Oct | 20:00 | 24:00 | S-L-0-25 | 54.00 | 158.2 | 10.58 | 147.6 | 4.01 | 0.584 | 4.10 | 29.86 | 80.4 | 3 | 0.542 | 29.28 |
| 15-Oct | 00:00 | 06:00 | S-L-0-26 | 53.90 | 157.2 | 10.83 | 146.3 | 2.58 | 0.392 | 3.57 | NA | NA | 6 | 2.330 | 124.02 |
| 15-Oct | 06:00 | 12:00 | S-L-0-27 | 54.00 | 155.1 | 9.75 | 145.3 | 2.31 | 0.417 | 3.54 | NA | NA | 5 | 1.841 | 88.77 |
| 19-Oct | 00:00 | 04:00 | S-L-0-28 | 54.00 | 158.1 | 10.47 | 147.6 | 4.33 | 0.551 | 4.10 | 29.88 | 54.9 | 3 | 0.724 | 39.47 |
| 0 ppm Formic Acid. 90% - 170 mesh Limestone | | | | | | | | | | | | | | | |
| 24-Oct | 08:00 | 12:00 | S-L-0-29 | 55.24 | 157.3 | 10.20 | 146.9 | 2.02 | 0.377 | 3.57 | 29.81 | 61.7 | 7 | 2.138 | 111.28 |
| 24-Oct | 12:00 | 16:00 | S-L-0-30 | 54.79 | 158.8 | 9.79 | 147.0 | 0.05 | 0.384 | 3.63 | 29.58 | 70.6 | 5 | 1.545 | 81.11 |
| 24-Oct | 16:00 | 20:00 | S-L-0-31 | 54.79 | 157.0 | 9.37 | 147.0 | 0.40 | 0.388 | 3.81 | 29.58 | 64.6 | 3 | 0.677 | 35.79 |
| 0 ppm Formic Acid. 90% -325 mesh LS. 5.0 pH | | | | | | | | | | | | | | | |
| 19-Oct | 12:00 | 16:00 | S-L-0-1A | 53.98 | 157.7 | 9.40 | 148.3 | 2.77 | 0.558 | 4.10 | 29.88 | 63.7 | 2 | 0.435 | 23.69 |
| 19-Oct | 16:00 | 20:00 | S-L-0-2A | 54.01 | 157.7 | 9.83 | 147.8 | 3.17 | 0.561 | 4.10 | 29.88 | 64.2 | 3 | 0.704 | 38.08 |
| 19-Oct | 20:00 | 24:00 | S-L-0-3A | 54.00 | 158.2 | 10.81 | 147.6 | 2.66 | 0.561 | 4.11 | 29.88 | 64.8 | 4 | 0.805 | 43.57 |
| 20-Oct | 00:00 | 04:00 | S-L-0-4A | 54.01 | 158.4 | 11.48 | 146.9 | 2.24 | 0.584 | 4.09 | 29.83 | 62.3 | 7 | 2.875 | 155.11 |
| 20-Oct | 04:00 | 08:00 | S-L-0-SA | 54.00 | 158.5 | 9.92 | 148.0 | 1.97 | 0.565 | 4.10 | 29.83 | 59.2 | 4 | 1.775 | 95.70 |
| 20-Oct | 08:00 | 12:00 | S-L-0-6A | 54.00 | 157.9 | 9.01 | 147.9 | 1.31 | 0.562 | 4.10 | 29.83 | 60.4 | 4 | 1.624 | 88.10 |

# TABLE 4.8.2-1. TEST CONDITIONS AND RESULTS

| 1995 Data | Start Time | End Time | Test Nov | Average Coal Flow ton/hr | Average Gross Load MW | Station Service Load MW | Average Net Load MW | Average Opacity % | Average Nov Emissions lb/MMBTU | Average O2 % | Baro-metric Pressure In Hg | Outdoor Temper-ature $^{o}$F | Total Nov of Headers Unit 2 | Unit 2 Mass Transfer Units NTU | KgaPV (=NTU* G) (kmol/hr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 400 ppm Formic Acid 90% -170 mesh Limestone | | | | | | | | | | | | | | | |
| 26-Oct | 12:00 | 18:00 | S-L-1-01 | 54.79 | 155.9 | 9.24 | 146.5 | 2.42 | 0.383 | 3.62 | 29.77 | | 3 | 1.014 | 52.78 |
| 26-Oct | 18:00 | 20:00 | S-L-1-02 | 54.79 | 156.3 | 9.59 | 146.7 | 0.64 | 0.390 | 3.59 | 29.77 | 58.6 | 4 | 2.259 | 117.50 |
| 28-Oct | 20:00 | 24:00 | S-L-1-03 | 54.79 | 156.4 | 9.46 | 146.9 | 1.44 | 0.390 | 3.63 | 29.77 | 57.1 | 4 | 1.988 | 102.30 |
| 27-Oct | 00:00 | 04:00 | S-L-1-04 | 54.78 | 156.0 | 10.09 | 145.8 | 1.54 | 0.358 | 3.77 | 29.01 | 53.0 | 3 | 1.580 | 84.05 |
| 27-Oct | 00:00 | 08:00 | S-L-1-05 | 55.13 | 156.2 | 9.58 | 146.6 | 2.40 | 0.389 | 3.78 | 29.61 | 53.0 | 4 | 2.287 | 120.71 |
| 27-Oct | 08:00 | 12:00 | S-L-1-06 | 55.39 | 158.1 | 9.76 | 148.3 | 2.01 | 0.385 | 3.80 | 29.61 | 52.4 | 5 | 1.944 | 103.54 |
| 27-Oct | 12:00 | 16:00 | S-L-1-07 | 54.78 | 157.7 | 9.33 | 148.3 | 1.87 | 0.388 | 3.77 | 29.41 | 56.2 | 3 | 1.042 | 86.95 |
| 27-Oct | 16:00 | 20:00 | S-L-1-08 | 54.79 | 157.9 | 10.07 | 147.8 | 1.87 | 0.379 | 3.78 | 29.41 | 59.8 | 5 | 2.803 | 148.54 |
| 27-Oct | 20:00 | 24:00 | S-L-1-09 | 54.79 | 158.5 | 9.87 | 148.5 | 1.89 | 0.389 | 3.78 | 20.41 | 61.9 | 5 | 2.690 | 142.16 |
| 30-Oct | 16:00 | 20:00 | S-L-1-10 | 54.79 | 158.0 | 10.38 | 147.8 | 1.45 | 0.385 | 3.85 | 29.82 | 48.8 | 2 | .588 | 135.69 |
| 30-Oct | 20:00 | 24:00 | S-L-1-11 | 54.80 | 159.3 | 10.75 | 148.5 | 2.06 | 0.379 | 3.83 | 30.03 | 44.1 | 7 | .238 | 189.44 |
| 30-Oct | 08 00 | 12:00 | S-L-1-12 | 54.78 | 158.8 | 9.28 | 147.5 | 2.75 | 0.387 | 3.86 | 29.82 | 47.4 | 2 | 0.652 | 34.77 |
| 31-Oct | 00:00 | 04:00 | S-L-1-13 | 54.55 | 160.2 | 10.26 | 149.9 | 2.21 | 0.379 | 3.B5 | 30.04 | 44.1 | 6 | 3.238 | 169.50 |
| 30-Oct | 12:00 | 16:00 | S-L-1-14 | 54.79 | 157.0 | 9.59 | 147.4 | 1.79 | 0.383 | 3.85 | 29.82 | 51.3 | 4 | 1.037 | 54.09 |
| 30-Oct | 04:00 | 08:00 | S-L-1-15 | 54.19 | 159.2 | 9.45 | 149.7 | 2.05 | 0.372 | 3.85 | 30.04 | 41.5 | 3 | 1.785 | 91.59 |
| 30-Oct | 08:00 | 12:00 | S-L-1-16 | 54.19 | 158.4 | 9.95 | 148.5 | 2.70 | 0.383 | 3.85 | 30.04 | 40.8 | 5 | 2.761 | 144.08 |
| 30-Oct | 12:00 | 16:00 | S-L-1-17 | 54.19 | 159.0 | 10.15 | 148.8 | 3.05 | 0.379 | 3.84 | 30.04 | 47.4 | 6 | 2.896 | 151.27 |
| 30-Oct | 16:00 | 20:00 | S-L-1-18 | 54.18 | 159.0 | 9.51 | 149.5 | 3.89 | 0.378 | 3.83 | 30.04 | 47.9 | 3 | 1.747 | 91.87 |
| 30-Oct | 20:00 | 00:00 | S-L-1-19 | 53.59 | 157.4 | 9.72 | 147.6 | 4.11 | 0.388 | 3.96 | 30.04 | 46.6 | 4 | 1.158 | 60.79 |
| 02-Nov | 00:00 | 04:00 | S-L-1-20 | 54.18 | 159.1 | 11.17 | 147.9 | 3.54 | 0.394 | 3.85 | 30.02 | 47.0 | 6 | 3.217 | 170.33 |
| 01-Nov | 04:00 | 08:00 | S-L-1-21 | 54.19 | 158.6 | 10.42 | 148.1 | 3.70 | 0.389 | 3.83 | 30.02 | 47.4 | 5 | 2.723 | 143.08 |
| 01-Nov | 08:00 | 12:00 | S-L-1-22 | 54.19 | 159.0 | 10.01 | 148.9 | 3.57 | 0.393 | 4.06 | 30.02 | 52.5 | 3 | 0.863 | 46.54 |
| 01-Nov | 12:00 | 16:00 | S-L-1-23 | 54.09 | 158.2 | 10.13 | 148.0 | 2.79 | 0.395 | 4.06 | 30.02 | 66.3 | 4 | 2.025 | 109.81 |
| 01-Nov | 16:00 | 20:00 | S-L-1-24 | 53.69 | 157.3 | 10.15 | 147.1 | 2.57 | 0.383 | 4.04 | 30.02 | 57.4 | 4 | 2.399 | 128.15 |
| 01-Nov | 20:00 | 24:00 | S-L-1-25 | 53.70 | 157.7 | 10.06 | 147.6 | 2.48 | 0.400 | 3.64 | 30.02 | 59.0 | 4 | 2.159 | 115.11 |
| 02-Nov | 00:00 | 04:00 | S-L-1-26 | 53.70 | 157.7 | 9.62 | 148.1 | 2.48 | 0.402 | 3.84 | 20.82 | 58.4 | 2 | 0.687 | 36.64 |
| 02-Nov | 04:00 | 08:00 | S-L-1-27 | 53.70 | 157.6 | 10.04 | 147.4 | 2.88 | 0.400 | 3.84 | 29.71 | 59.0 | 5 | 2.138 | 113.91 |
| 02-Nov | 08:00 | 12:00 | S-L-1-28 | 53.70 | 157.8 | 10.75 | 147.0 | 0.95 | 0.387 | 3.77 | 29.61 | 65.2 | 7 | 3.329 | 175.54 |
| 400 ppm Formic Acid 90% -325 mesh Limestone | | | | | | | | | | | | | | | |
| 08-Nov | 08:00 | 12:00 | S-L-1-29 | 54.00 | 157.8 | 10.08 | 147.7 | 4.63 | 0.367 | 3.86 | 29.94 | 38.9 | 5 | 3.309 | 176.70 |
| 06-Nov | 12:00 | 16:00 | S-L-1-30 | 53.99 | 159.3 | 10.59 | 148.8 | 1.86 | 0.373 | 3.87 | 29.94 | 40.9 | 7 | 3.636 | 195.10 |
| 08-Nov | 16:00 | 20:00 | S-L-1-31 | 53.40 | 157.1 | 9.68 | 147.4 | 2.04 | 0.384 | 3.86 | 29.94 | 45.7 | 3 | 2.150 | 114.44 |

# TABLE 4.8.2-1. TEST CONDITIONS AND RESULTS

| 1995 Data | Start Time | End Time | Test Nov | Average Coal Flow ton/hr | Average Gross Load MW | Station Service Load MW | Average Net Load MW | Average Opacity % | Average Nov Emissions lb/MMBTU | Average O2 % | Baro-metric Pressure In Hg | Outdoor Temper-ature $^{o}$F | Total Nov of Headers Unit 2 | Unit 2 Mass Transfer Units NTU | KgaPV (=NTU* G) (kmol/hr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 800 ppm Formic Acid 90% - 170 mesh Limestone | | | | | | | | | | | | | | | |
| 15-Nov | 20:00 | 24:00 | S-L-2-01 | 54.21 | 155.9 | 9.72 | 146.1 | 5.37 | 0.383 | 3.80 | 29.39 | 35.1 | 4 | 1.334 | 71.07 |
| 16-Nov | 00:00 | 04:00 | S-L-2-02 | 54.08 | 158.5 | 10.28 | 145.2 | 5.34 | 0.381 | 3.81 | 29.53 | 34.3 | 3 | 1.218 | 65.24 |
| 16-Nov | 04:00 | 08:00 | S-L-2-03 | 54.22 | 155.2 | 10.27 | 144.9 | 3.54 | 0.392 | 3.81 | 29.53 | 32.7 | 6 | 3.977 | 210.39 |
| 16-Nov | 08:00 | 12:00 | S-L-2-04 | 54.23 | 155.4 | 9.78 | 145.0 | 5.00 | 0.385 | 3.79 | 29.64 | 33.7 | 4 | 2.880 | 153.43 |
| 16-Nov | 12:00 | 18:00 | S-L-2-05 | 54.29 | 155.0 | 9.95 | 144.9 | 4.57 | 0.383 | 3.80 | 29.74 | 38.5 | 5 | 3.289 | 172.26 |
| 16-Nov | 10:00 | 20:00 | S-L-2-06 | 64.90 | 158.3 | 9.70 | 140.6 | 3.98 | 0.374 | 3.79 | 29.74 | 35.4 | 3 | 2.807 | 139.78 |
| 16-Nov | 20:00 | 24:00 | S-L-2-07 | 54.69 | 157.8 | 10.57 | 147.2 | 4.35 | 0.372 | 3.76 | 29.74 | 35.4 | 7 | 3.823 | 204.34 |
| 17-Nov | 04:00 | 00:00 | S-L-2-08 | 55.19 | 158.0 | 10.20 | 147.7 | 3.64 | 0.392 | 3.82 | 29.84 | 34.3 | 5 | 3.499 | 180.78 |
| 17-Nov | 08:00 | 12:00 | S-L-2-09 | 55.20 | 158.7 | 0.29 | 147.3 | 5.05 | 0.392 | 3.81 | 29.84 | 35.8 | 2 | 0.810 | 42.97 |
| 17-Nov | 12:00 | 16:00 | S-L-2-10 | 55.20 | 155.3 | 9.98 | 148.3 | 3.69 | 0.388 | 3.82 | 29.84 | 39.8 | 6 | 2.533 | 133.87 |
| 17-Nov | 18:00 | 20:00 | S-L-2-11 | 54.60 | 156.5 | 9.51 | 145.0 | 3.17 | 0.379 | 3.78 | 29.84 | 37.3 | 3 | 2.209 | 115.78 |
| 17-Nov | 20:00 | 24:00 | S-L-2-12 | 54.60 | 156.8 | 10.44 | 146.3 | 3.33 | 0.388 | 3.83 | 29.84 | 33.1 | 4 | 3.138 | 163.40 |
| 18-Nov | 08:00 | 12:00 | S-L-2-13 | 54.80 | 156.1 | 10.19 | 145.8 | 3.88 | 0.394 | 3.78 | 29.99 | 34.6 | 6 | 3.457 | 183.52 |
| 18-Nov | 12:00 | 16:00 | S-L-2-14 | 54.80 | 156.3 | 9.83 | 148.4 | 3.32 | 0.394 | 3.80 | 29.77 | 37.0 | 4 | 3.050 | 163.26 |
| 18-Nov | 16:00 | 20:00 | S-L-2-15 | 54.60 | 158.8 | 9.41 | 147.3 | 4.29 | 0.390 | 3.83 | 29.77 | 37.0 | 2 | 0.757 | 40.83 |
| 18-Nov | 20:00 | 24:00 | S-L-2-16 | 55.20 | 158.5 | 9.83 | 148.7 | 3.78 | 0.396 | 3.81 | 29.77 | 37.0 | 4 | 2.911 | 156.00 |
| 19-Nov | 16:00 | 20:00 | S-L-2-17 | 54.37 | 156.7 | 9.77 | 146.9 | 3.23 | 0.384 | 4.04 | 29.77 | 37.0 | 4 | 1.163 | 51.83 |
| 19-Nov | 20:00 | 24:00 | S-L-2-18 | 54.30 | 156.3 | 10.73 | 145.5 | 3.33 | 0.378 | 4.04 | 29.77 | 38.4 | 6 | 3.571 | 188.99 |
| 20-Nov | 08:00 | 12:00 | S-L-2-19 | 53.70 | 156.2 | 9.65 | 148.5 | 3.77 | 0.379 | 3.65 | 29.93 | 38.2 | 4 | 3.054 | 157.49 |
| 20-Nov | 12:00 | 18:00 | S-L-2-20 | 53.55 | 157.3 | 9.38 | 147.8 | 11.88 | 0.380 | 3.58 | 29.73 | 42.6 | 3 | 2.671 | 138.34 |
| 20-Nov | 18:00 | 20:00 | S-L-2-21 | 54.00 | 158..2 | 10.39 | 147.8 | 11.75 | 0.399 | 3.49 | 29.73 | 41.4 | 7 | 3.901 | 204.42 |
| 20-Nov | 20:00 | 24:00 | S-L-2-22 | 54.00 | 159.2 | 10.12 | 149.0 | 12.88 | 0.398 | 3.51 | 29.73 | 41.4 | 6 | 4.085 | 212.13 |
| 21-Nov | 00:00 | 04:00 | S-L-2-23 | 54.00 | 159.0 | 10.07 | 148.9 | 12.70 | 0.393 | 3.52 | 29.54 | 41.7 | 5 | 3.712 | 197.08 |
| 21-Nov | 04:00 | 08:00 | S-L-2-24 | 54.00 | 159.0 | 9.72 | 149.2 | 13.77 | 0.372 | 3.50 | 29.54 | 40.8 | 5 | 2.756 | 142.21 |
| 21-Nov | 08:00 | 12:00 | S-L-2-25 | 54.00 | 158.6 | 9.81 | 148.8 | 6.98 | 0.379 | 3.50 | 29.54 | 44.2 | 5 | 3.603 | 188.28 |
| 21-Nov | 12:00 | 16:00 | S-L-2-26 | 54.00 | 158.9 | 9.48 | 149.4 | 4.04 | 0.386 | 3.50 | 29.54 | 38.4 | 3 | 1.229 | 84.03 |
| 21-Nov | 16:00 | 20:00 | S-L-2-27 | 53.40 | 157.1 | 9.85 | 147.4 | 3.30 | 0.387 | 3.50 | 29.54 | 37.5 | 4 | 3.205 | 164.48 |
| 21-Nov | 20:00 | 24:00 | S-L-2-28 | 53.39 | 157.1 | 9.32 | 147.7 | 3.74 | 0.387 | 3.51 | 29.54 | 35.4 | 3 | 2.361 | 121.23 |
| 800 ppm Formic Acid 90% -325 mesh Limestone | | | | | | | | | | | | | | | |
| 09-Nov | 08:00 | 12:00 | S-L-2-29 | 53.52 | 154.9 | 10.53 | 144.3 | 2.37 | 0.391 | 3.83 | 29.84 | 30.5 | 7 | 4.373 | 228. 70 |
| 09-Nov | 12:00 | 16:00 | S-L-2-30 | 53.62 | 150.0 | 10.14 | 145.8 | 2.39 | 0.378 | 3.05 | 29.85 | 34.0 | 5 | 3.657 | 191.59 |
| 09-Nov | 16:00 | 20:00 | S-L-2-31 | 54.22 | 157.3 | 9.75 | 147.5 | 3.78 | 0.381 | 3.79 | 29.85 | 34.2 | 3 | 2.609 | 138.80 |
| High Velocity Tests, 800 ppm Formic Acid | | | | | | | | | | | | | | | |
| 13-Nov | 08:00 | 12:00 | H-L-2-00 | 72.3 | 202.9 | 12.70 | 180.8 | 0.45 | 4.767 | 1.50 | 29.83 | 30.8 | 7 | 4.131 | 318.53 |
| 13-Nov | 12:00 | 16:00 | H-L-2-01 | 80.0 | 220.8 | 12.24 | 211.2 | 0.00 | 4.422 | 1.50 | 29.83 | 31.9 | 4 | 2.381 | 197.77 |
| 13-Nov | 16:00 | 20:00 | H-L-2-02 | 74.3 | 209.0 | 12.37 | 193.1 | 0.04 | 4.221 | 1.63 | 29.83 | 31.9 | 5 | 3.457 | 269.57 |
| 13-Nov | 20:00 | 24:00 | H-L-2-03 | 74.9 | 211.6 | 12.15 | 196.2 | 0.63 | 4.753 | 1.59 | 29.83 | 33.8 | 5 | 2.677 | 211.72 |
| 14-Nov | 00:00 | 04:00 | H-L-2-04 | 75.7 | 213.7 | 13.01 | 197.1 | 0.02 | 0.385 | 4.75 | 29.77 | 34.9 | 7 | 4.131 | 332.13 |
| 14-Nov | 04:00 | 08:00 | H-L-2-05 | 75.8 | 213.5 | 12.59 | 198.3 | 0.28 | 0.385 | 4.77 | 29.77 | 34.3 | 5 | 3.597 | 288.07 |
| 14-Nov | 08:00 | 12:00 | H-L-2-06 | 75.7 | 213.9 | 12.50 | 198.4 | 0.20 | 0.382 | 4.52 | 29.77 | 34.3 | 5 | 2.600 | 208.89 |
| 14-Nov | 12:00 | 16:00 | H-L-2-07 | 75.7 | 213.9 | 12.70 | 198.2 | 0.07 | 0.384 | 4.52 | 29.77 | 35.0 | 6 | 3.480 | 277.92 |
| 14-Nov | 16:00 | 20:00 | H-L-2-08 | 75.7 | 213.5 | 12.88 | 197.5 | -0.01 | 0.392 | 4.50 | 29.66 | 35.0 | 6 | 3.780 | 303.79 |
| 14-Nov | 20:00 | 24:00 | H-L-2-09 | 75.7 | 213.5 | 12.58 | 197.9 | -0.01 | 0.387 | 4.52 | 29.43 | 33.0 | 5 | 3.140 | 253.90 |
| 15-Nov | 00:00 | 04:00 | H-L-2-10 | 75.8 | 214.0 | 12.53 | 198.3 | -0.01 | 0.387 | 4.51 | 29.28 | 33.0 | 5 | 3.112 | 254.78 |
| 15-Nov | 04:00 | 08:00 | H-L-2-11 | 75.9 | 213.1 | 12.71 | 197.2 | 1.09 | 0.383 | 4.52 | 29.26 | 33.0 | 6 | 3.066 | 252.58 |
| 15-Nov | 08:00 | 12:00 | H-L-2-12 | 76.0 | 213.2 | 12.80 | 196.4 | 0.02 | 0.374 | 4.52 | 29.05 | 34.1 | 6 | 3.814 | 313.32 |
| 15-Nov | 12:00 | 15:00 | H-L-2-13 | 76.0 | 213.9 | 12.31 | 198.0 | -0.01 | 0.373 | 4.53 | 29.05 | 34.1 | 4 | 2.877 | 230.37 |

# TABLE 4.8.2-1.  TEST CONDITIONS AND RESULTS

| 1995 | Start | End | Test | Formic | Absorber Slurry | Absorber Solution Analysis | | | Limestone Slurry Particle Size | | Target Limestone | Formic Acid Pump Settings | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Data | Time | Time | Nov | Acid Analysis ppm wt. | Carbonat e Analysis | Chloride ppm wt. | Sulfate ppm wt. | Sulfite ppm wt. | % -170 mesh | % -325 mesh | Grind Size (mesh) | AMP-101 | AMP-201 | AMP-301 |
| 0 ppm Formic Acid, 90% -325 mesh Limestone | | | | | | | | | | | | | | |
| 11-Oct | 12:00 | 18:00 | S-L-0-01 | 46.6 | 1.00 | 38,000 | 13,168 | 0.096 | | 96.89 | 325 | 0 | 0 | 0 |
| 11-Oct | 18:00 | 24:00 | S-L-0-02 | 46.6 | 1.80 | 38,000 | 12,878 | 0.064 | | 98.99 | 325 | 0 | 0 | 0 |
| 12-Oct | 00:00 | 06:00 | S-L-0-03 | 46.6 | 1.50 | | | | | | 325 | 0 | 0 | 0 |
| 12-Oct | 06:00 | 12:00 | S-L-0-04 | 18.6 | 1.40 | | | | | | 325 | 0 | 0 | 0 |
| 12-Oct | 12:00 | 18:00 | S-L-0-05 | 18.6 | 0.80 | | | | | | 325 | 0 | 0 | 0 |
| 12-Oct | 18:00 | 24:00 | S-L-0-05 | 18.6 | 1.20 | | | | | | 325 | 0 | 0 | 0 |
| 13-Oct | 00:00 | 06:00 | S-L-0-07 | 18.6 | 0.80 | | | | | | 325 | 0 | 0 | 0 |
| 13-Oct | 06:00 | 12:00 | S-L-0-08 | 28.0 | 1.20 | | | | | | 325 | 0 | 0 | 0 |
| 13-Oct | 12:00 | 18:00 | S-L-0-09 | 37.3 | 0.80 | | | | | | 325 | 0 | 0 | 0 |
| 16-Oct | 20:00 | 24:00 | S-L-0-10 | 102.5 | 2.00 | | | | | | 325 | 0 | 0 | 0 |
| 17-Oct | 07:00 | 12:00 | S-L-0-11 | 111.8 | 2.01 | 50,000 | 15,049 | 0.096 | | | 325 | 0 | 0 | 0 |
| 17-Oct | 12:00 | 16:00 | S-L-0-12 | 111.8 | 1.60 | 54,000 | 14,615 | 0.084 | | | 325 | 0 | 0 | 0 |
| 17-Oct | 16:00 | 20:00 | S-L-0-13 | 102.5 | 0.40 | 52,000 | 13,188 | 0.064 | | | 325 | 0 | 0 | 0 |
| 13-Oct | 18:00 | 24:00 | S-L-0-14 | 48.8 | 0.60 | 39,000 | 14,036 | 0.064 | | | 325 | 0 | 0 | 0 |
| 17-Oct | 20:00 | 24:00 | S-L-0-15 | 74.6 | 0.80 | | | | | | 325 | 0 | 0 | 0 |
| 18-Oct | 00:00 | 04:00 | S-L-0-16 | 46.8 | 1.20 | | | | | | 325 | 0 | 0 | 0 |
| 14-Oct | 00:00 | 06:00 | S-L-0-17 | 55.9 | 0.80 | | | | | | 325 | 0 | 0 | 0 |
| 18-Oct | 04:00 | 08:00 | S-L-0-18 | 46.6 | 0.80 | | | | | | 325 | 0 | 0 | 0 |
| 18-Oct | 08:00 | 12:00 | S-L-0-19 | 65.2 | 0.40 | | | | | | 325 | 0 | 0 | 0 |
| 14-Oct | 06:00 | 12:00 | S-L-0-20 | 83.9 | 0.50 | | | | | | 325 | 0 | 0 | 0 |
| 18-Oct | 12:00 | 16:00 | S-L-0-21 | 65.2 | 0.41 | | | | | | 325 | 0 | 0 | 0 |
| 14-Oct | 12:00 | 18:00 | S-L-0-22 | 83.9 | 1.99 | | | | | | 325 | 0 | 0 | 0 |
| 14-Oct | 18:00 | 24:00 | S-L-0-23 | 93.2 | 2.00 | 48,000 | 8,882 | 0.064 | | | 325 | 0 | 0 | 0 |
| 18-Oct | 16:00 | 20:00 | S-L-0-24 | 74.8 | 0.00 | 41,500 | 13,747 | 0.064 | | | 325 | 0 | 0 | 0 |
| 18-Oct | 20:00 | 24:00 | S-L-0-25 | 37.3 | 0.80 | 32,000 | 15,049 | 0.064 | | | 325 | 0 | 0 | 0 |
| 15-Oct | 00:00 | 06:00 | S-L-0-26 | 65.2 | 1.99 | 43,000 | 8,071 | 0.098 | | | 325 | 0 | 0 | 0 |
| 15-Oct | 06:00 | 12:00 | S-L-0-27 | 05.2 | 1.99 | | | | | 93.71 | 325 | 0 | 0 | 0 |
| 19-Oct | 00:00 | 04:00 | S-L-0-28 | 9.3 | 0.40 | | | | | 89.12 | 325 | 0 | 0 | 0 |
| 0 ppm Formic Acid, 90% - 170 mesh Limestone | | | | | | | | | | | | | | |
| 24-Oct | 08:00 | 12:00 | S-L-0-29 | 55.9 | 0.40 | 43,000 | 15,338 | 0.096 | 97.88 | | 170 | 0 | 0 | 0 |
| 24-Oct | 12:00 | 16:00 | S-L-0-30 | 55.9 | 0.80 | 41,000 | 16,206 | 0.128 | 97.94 | | 170 | 0 | 0 | 0 |
| 24-Oct | 16:00 | 20:00 | S-L-0-31 | 65.2 | 0.40 | 44,000 | 15,483 | 0.090 | 97.98 | | 170 | 0 | 0 | 0 |
| 0 ppm Formic Acid, 90% - 325 mesh LS, 5.0  pH | | | | | | | | | | | | | | |
| 19-Oct | 12:00 | 16:00 | S-L-0-1A | 18.8 | 1.56 | 27,000 | 16.496 | 0.064 | | | 325 | 0 | 0 | 0 |
| 19-Oct | 16:00 | 20:00 | S-L-0-2A | 28.0 | 1.98 | 27,000 | | | | | 325 | 0 | 0 | 0 |
| 19-Oct | 20:00 | 24:00 | S-L-0-3A | 28.0 | 2.28 | 30,000 | | | | | 325 | 0 | 0 | 0 |
| 20-Oct | 00:00 | 04:00 | S-L-0-4A | 37.3 | 4.37' | 32,000 | | | | | 325 | 0 | 0 | 0 |
| 20-Oct | 04:00 | 08:00 | S-L-0-5A | 46.8 | 3.38 | 33,000 | | | | | 325 | 0 | 0 | 0 |
| 20-Oct | 08:00 | 12:00 | S-L-0-6A | 74.8 | 3.42 | 35,000 | 15,483 | 0.096 | | | 325 | 0 | 0 | 0 |

# TABLE 4.8.2-1. TEST CONDITIONS AND RESULTS

| 1995 Data | Start Time | End Time | Test Nov | Formic Acid Analysis ppm wt. | Absorber Slurry Carbonate Analysis | Absorber Solution Analysis | | | Limestone Slurry Particle Size | | Target Limestone Grind Size (mesh) | Formic Acid Pump Settings | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Chloride ppm wt. | Sulfate ppm wt. | Sulfite ppm wt. | % -170 mesh | % -325 mesh | | AMP-101 | AMP-201 | AMP-301 |
| 400 ppm Formic Acid 90% - 170 mesh Limestone | | | | | | | | | | | | | | |
| 26-Oct | 12:00 | 16:00 | S-L-1-01 | 438.0 | 1.19 | 41,000 | 15,428 | 0.128 | | | 170 | 0 | 30 | 0 |
| 26-Oct | 16:00 | 20:00 | S-L-1-02 | 447.4 | 1.20 | 47,000 | 15,049 | 0.064 | | | 170 | 0 | 30 | 0 |
| 26-Oct | 20:00 | 24:00 | S-L-1-03 | 447.4 | 0.80 | | | | | | 170 | 0 | 30 | 0 |
| 27-Oct | 00:00 | 04:00 | S-L-1-04 | 468.0 | 0.80 | | | | | | 170 | 0 | 30 | 0 |
| 27-Oct | 04:00 | 08:00 | S-L-1-05 | 494.0 | 1.19 | | | | | | 170 | 0 | 30 | 0 |
| 27-Oct | 08:00 | 12:00 | S-L-1-06 | 438.0 | 1.19 | | | | | | 170 | 30 | 20 | 0 |
| 27-Oct | 12:00 | 16:00 | S-L-1-07 | 587.2 | 1.60 | | | | | | 170 | 30 | 20 | 0 |
| 27-Oct | 16:00 | 20:00 | S-L-1-08 | 540.8 | 1.60 | | | | | | 170 | 30 | 20 | 0 |
| 27-Oct | 20:00 | 24:00 | S-L-1-09 | 815-1 | 1.81 | | | | | | 170 | 30 | 30 | 0 |
| 30-Oct | 16:00 | 20:00 | S-L-1-10 | 382.1 | 1.81 | | | | | | 170 | 30 | 30 | 0 |
| 30-Oct | 20:00 | 24:00 | S-L-1-11 | 410.1 | 2.01 | 38,000 | 18,956 | 0.180 | 97.88 | | 170 | 30 | 30 | 0 |
| 30-Oct | 08:00 | 12:00 | S-L-1-12 | 307.8 | 0.80 | 34,000 | 15,917 | 0.130 | 97.70 | | 170 | 30 | 30 | 0 |
| 31-Oct | 00:00 | 04:00 | S-L-1-13 | 438.0 | 1.81 | 41,000 | 17,509 | 0.130 | 97.88 | | 170 | 30 | 40 | 0 |
| 30-Oct | 12:00 | 16:00 | S-L-1-14 | 298.2 | 0.50 | 32,000 | 15,338 | 0.260 | 97.68 | | 170 | 30 | 40 | 0 |
| 31-Oct | 04:00 | 08:00 | S-L-1-15 | 372.8 | 1.60 | | | | | | 170 | 30 | 40 | 0 |
| 31-Oct | 08:00 | 12:00 | S-L-1-16 | 475.3 | 2.00 | | | | | | 170 | 30 | 40 | 0 |
| 31-Oct | 12:00 | 16:00 | S-L-1-17 | 410.1 | 1.20 | | | | | | 170 | 30 | 40 | 0 |
| 31-Oct | 16:00 | 20:00 | S-L-1-18 | 428.7 | 0.40 | | | | | | 170 | 30 | 40 | 0 |
| 31-Oct | 20:00 | 00:00 | S-L-1-19 | 456.7 | 1.61 | | | | | | 170 | 30 | 40 | 0 |
| 01-Nov | 00:00 | 04:00 | S-L-1-20 | 512.8 | 1.20 | | | | | | 170 | 30 | 40 | 0 |
| 01-Nov | 04:00 | 08:00 | S-L-1-21 | 512.6 | 1.20 | | | | | | 170 | 30 | 40 | 0 |
| 01-Nov | 08:00 | 12:00 | S-L-1-22 | 521.9 | 1.81 | | | | | | 170 | 30 | 40 | 0 |
| 01-Nov | 12:00 | 16:00 | S-L-1-23 | 531.2 | 2.39 | 48,000 | 14,904 | 0.098 | | | 170 | 30 | 40 | 0 |
| 01-Nov | 16:00 | 20:00 | S-L-1-24 | 512.6 | 2.39 | 43,000 | 14,038 | 0.032 | | | 170 | 30 | 40 | 0 |
| 01-Nov | 20:00 | 24:00 | S-L-1-25 | 540.8 | 3.19 | 51,000 | 14,904 | 0.090 | | | 170 | 30 | 40 | 0 |
| 02-Nov | 00:00 | 04:00 | S-L-1-26 | 484.6 | 1.99 | 47,000 | 15,049 | 0.120 | | | 170 | 30 | 40 | 0 |
| 02-Nov | 04:00 | 08:00 | S-L-1-27 | 438.0 | 2.79 | | | | | | 170 | 30 | 40 | 0 |
| 02-Nov | 08:00 | 12:00 | S-L-1-28 | 419.4 | 2.79 | | | | | | 170 | 30 | 40 | 0 |
| 400 ppm Formic Acid 90% -325 mesh Limestone | | | | | | | | | | | | | | |
| 06-Nov | 08:00 | 12:00 | S-L-1-29 | 540.0 | 1.60 | 42,000 | 15,049 | 0.160 | | 91.97 | 325 | 30 | 40 | 0 |
| 06-Nov | 12:00 | 10:00 | S-L-1-30 | 577.6 | 1.61 | 54,000 | 15,428 | 0.090 | | 91.82 | 325 | 30 | 30 | 0 |
| 06-Nov | 18:00 | 20:00 | S-L-1-31 | 652.4 | 1.60 | 48,000 | 14,898 | 0.128 | | 22.08 | 325 | 30 | 30 | 0 |

# TABLE 4.8.2-1. TEST CONDITIONS AND RESULTS

| 1995 Data | Start Time | End Time | Test Nov | Formic Acid Analysis ppm wt. | Absorber Slurry Carbonate Analysis | Absorber Solution Analysis | | | Limestone Slurry Particle Size | | Target Limestone Grind Size (mesh) | Formic Acid Pump Settings | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Chloride ppm wt. | Sulfate ppm wt. | Sulfite ppm wt. | % -170 mesh | % -325 mesh | | AMP-101 | AMP-201 | AMP-301 |
| 800 ppm Formic Acid 90% - 170 mesh Limestone | | | | | | | | | | | | | | |
| 15-Nov | 20:00 | 24:00 | S-L-2-01 | 868.8 | 1.20 | 46,000 | 13,023 | 0.480 | 99.01 | | 170 | 30 | 25 | 0 |
| 16-Nov | 00:00 | 04:00 | S-L-2-02 | 969.3 | 1.60 | 47,000 | 13,602 | 0.084 | 98.33 | | 170 | 30 | 25 | 0 |
| 16-Nov | 04:00 | 08:00 | S-L-2-03 | 820.2 | 2.00 | | | | | | 170 | 30 | 25 | 0 |
| 16-Nov | 08:00 | 12:00 | S-L-2-04 | 784.2 | 1.59 | | | | | | 170 | 30 | 25 | 0 |
| 16-Nov | 12:00 | 16:00 | S-L-2-05 | 1287.5 | 2.39 | | | | | | 170 | NA | NA | NA |
| 16-Nov | 16:00 | 20:00 | S-L-2-08 | 941.3 | 2.00 | | | | | | 170 | 25 | 20 | 0 |
| 10-Nov | 20:00 | 24:00 | S-L-2-07 | 904.0 | 2.00 | | | | | | 170 | 25 | 20 | 0 |
| 17-Nov | 04:00 | 08:00 | S-L-2-08 | 838.8 | 1.61 | | | | | | 170 | 25 | 20 | 0 |
| 17-Nov | 08:00 | 12:00 | S-L-2-09 | 754.9 | 1.00 | | | | | | 170 | 25 | 20 | 0 |
| 17-Nov | 12:00 | 16:00 | S-L-2-10 | 745.6 | 1.60 | | | | | | 170 | 25 | 20 | 0 |
| 17-Nov | 16:00 | 20:00 | S-L-2-11 | 894.7 | 1.60 | 47,000 | 14,615 | 0.288 | | | 170 | 25 | 25 | 0 |
| 17-Nov | 20:00 | 24:00 | S-L-2- 12 | 922.7 | 2.00 | 49,000 | 14,470 | 0.256 | | | 170 | 25 | 25 | 0 |
| 18-Nov | 08:00 | 12:00 | S-L-2-13 | 876.1 | 2.00 | 48,000 | 14,759 | 0.288 | | | 170 | 25 | 25 | 0 |
| 18-Nov | 12:00 | 16:00 | S-L-2-14 | 922.7 | 3.80 | 48,000 | 13,457 | 0.320 | | | 170 | 25 | 25 | 0 |
| 18-Nov | 16:00 | 20:00 | S-L-2-15 | 978.6 | 4.42 | | | | | | 170 | 25 | 25 | 0 |
| 15-Nov | 20:00 | 24:00 | S-L-2-16 | 1062.5 | 4.40 | | | | | | 170 | 25 | 25 | 0 |
| 19-Nov | 16:00 | 20:00 | S-L-2-17 | 792.2 | 1.21 | | | | | | 170 | 25 | 25 | 0 |
| 19-Nov | 20:00 | 24:00 | S-L-2-18 | 848.1 | 1.61 | | | | | | 170 | 25 | 25 | 0 |
| 20-Nov | 08:00 | 12:00 | S-L-2-19 | 922.7 | 1.81 | | | | | | 170 | 25 | 25 | 0 |
| 20-Nov | 12:00 | 16:00 | S-L-2-20 | 1015.9 | 1.21 | | | | | | 170 | 25 | 25 | 0 |
| 20-Nov | 16:00 | 20:00 | S-L-2-21 | 1118.4 | 0.80 | | | | | | 170 | 25 | 20 | 0 |
| 20-Nov | 20:00 | 24:00 | S-L-2-22 | 1174.3 | 0.81 | | | | | | 170 | 25 | 20 | 0 |
| 21-Nov | 00:00 | 04:00 | S-L-2-23 | 1165.0 | 1.61 | 60,000 | 11,885 | 0.064 | | | 170 | 25 | 20 | 0 |
| 21-Nov | 04:00 | 08:00 | S-L-2-24 | 1183.6 | 0.12 | 60,000 | 11,865 | 0.480 | | | 170 | 25 | 20 | 0 |
| 21-Nov | 08:00 | 12:00 | S-L-2-25 | 1081.1 | 2.01 | 58,000 | 9,984 | 0.570 | | | 170 | 20 | 20 | 0 |
| 21-Nov | 12:00 | 16:00 | S-L-2-25 | 1193.0 | 1.81 | 64,000 | 11,142 | 0.448 | | | 170 | 20 | 20 | 0 |
| 21-Nov | 16:00 | 20:00 | S-L-2-27 | 1202.3 | 2.01 | | | | 93.15 | | 170 | 15 | 15 | 0 |
| 21-Nov | 20:00 | 24:00 | S-L-2-28 | 1239.6 | 2.00 | | | | 93.05 | | 170 | 15 | 15 | 0 |
| 800 ppm Formic Acid, 90% -325 mesh Limestone | | | | | | | | | | | | | | |
| 09-Nov | 08:00 | 12:00 | S-L-2-29 | 615.1 | 1.00 | 34,000 | 16,390 | 0.448 | | 92.47 | 325 | NA | NA | NA |
| 09-Nov | 12:00 | 16:00 | S-L-2-30 | 615.1 | 1.01 | 34,000 | 15,772 | 0.288 | | 93.30 | 325 | NA | NA | NA |
| 09-Nov | 16:00 | 20:00 | S-L-2-31 | 829.5 | 1.20 | 37,000 | 15,194 | 0.640 | | 92.43 | 325 | NA | NA | NA |
| High Velocity Tests, 800 ppm Formic Acid | | | | | | | | | | | | | | |
| 13-Nov | 08:00 | 12:00 | H-L-2-00 | | | | | | | | 170 | 0 | 40 | 0 |
| 13-Nov | 12:00 | 16:00 | H-L-2-01 | 1211.6 | 2.00 | | | | | | 170 | 0 | 40 | 0 |
| 13-Nov | 16:00 | 20:00 | H-L-2-02 | 1395.0 | 1.99 | | | | | | 170 | 0 | 40 | 0 |
| 13-Nov | 20:00 | 24:00 | H-L-2-03 | 1444.6 | 2.81 | 49,000 | 15,194 | 0.128 | | | 170 | 0 | 40 | 0 |
| 14-Nov | 00:00 | 04:00 | H-L-2-04 | 1295.5 | 2.81 | 43,000 | 15,338 | 0.832 | | | 170 | 0 | 40 | 0 |
| 14-Nov | 04:00 | 08:00 | H-L-2-05 | 1155.7 | 2.42 | 43,000 | 15,194 | 0.768 | | | 170 | 0 | 30 | 0 |
| 14-Nov | 08:00 | 12:00 | H-L-2-06 | 1280.2 | 2.82 | 43,000 | 15,338 | 0.608 | | | 170 | 0 | 25 | 0 |
| 14-Nov | 12:00 | 16:00 | H-L-2-07 | 1248.9 | 1.21 | | | | | | 170 | 0 | 25 | 0 |
| 14-Nov | 16:00 | 20:00 | H-L-2-08 | 1155.0 | 0.80 | | | | | | 170 | 0 | 25 | 0 |
| 14-Nov | 20:00 | 24:00 | H-L-2-09 | 1155.7 | 1.20 | | | | | | 170 | 0 | 25 | 0 |
| 15-Nov | 00:00 | 04:00 | H-L-2-10 | 1043.8 | 0.80 | | | | | | 170 | 0 | 25 | 0 |
| 15-Nov | 04:00 | 08:00 | H-L-2-11 | 980.0 | 1.20 | | | | 97.50 | | 170 | 0 | 25 | 0 |
| 15-Nov | 08:00 | 12:00 | H-L-2-12 | 894.7 | 1.61 | | | | 97.66 | | 170 | 0 | 25 | 0 |
| 15-Nov | 12:00 | 16:00 | H-L-2-13 | 978.6 | 1.00 | | | | 97.50 | | 170 | 0 | 25 | 0 |

## TABLE 4.8.2-2.
## LABORATORY ANALYSIS OF GYPSUM SAMPLES

| | Wt. % Free Moisture | Wt. % Combined Water | | Formic Acid | Soluble Chloride | Major Ash Analysis, Wt. % As Determined | | | | | | | | Wt. % Gypsum Dry Basis | Wt % $CaCO_3$ Dry Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Test Number | As. Deter. | As. Deter. | Corrected to 0% Moisture | ppm Wt As. Deter. | ppm Wt As. Deter. | CO3 | CaO | $SO_3$ | $SiO_2$ | $Al_2O_3$ | $Fe_2O_3$ | MgO | $NA_2O$ + $K_2O$ | (Based on Combined Water) | (Based on $CO_3$ Analysis) |
| H-L-2-04 | 4.6 | 19.19 | 20.12 | <10 | 281 | 1.87 | 31.53 | 45.96 | 0.56 | 0.17 | 0.10 | 0.48 | 0.07 | 96.1 | 3.12 |
| S-L-0-02 | 5.56 | 19.22 | 20.35 | <10 | 441 | 1.17 | 30.37 | 44.58 | 0.53 | 0.17 | 0.11 | 0.33 | 0.08 | 97.2 | 1.95 |
| S-L-0- | 3.25 | 19.52 | 20.18 | <10 | 173 | 1.69 | 31.54 | 45.76 | 0.55 | 0.14 | 0.10 | 0.32 | 0.08 | 96.4 | 2.82 |
| S-L-0-12 | 6.01 | 19.07 | 20.29 | <10 | 187 | 1.14 | 30.44 | 43.77 | | | | | | 97.0 | 1.90 |
| S-L-0-23 | 8.09 | 18.80 | 20.45 | 43 | 148 | 0.56 | 29.90 | 44.65 | | | | | | 97.7 | 0.93 |
| S-L-0-25 | 7.28 | 18.88 | 20.36 | <10 | 168 | 0.81 | 29.13 | 43.52 | | | | | | 97.3 | 1.35 |
| S-L-0-29 | 5.4 | 19.35 | 20.45 | <10 | 183 | 0.73 | 30.66 | 46.16 | | | | | | 97.7 | 1.22 |
| S-L-1-01 | 7.28 | 18.90 | 20.38 | <10 | 186 | 0.86 | 29.50 | 44.53 | 0.64 | 0.21 | 0.11 | 0.24 | 0.08 | 97.4 | 1.43 |
| S-L-1-12 | 5.22 | 19.37 | 20.44 | <10 | 161 | 0.91 | 29.59 | 45.07 | | | | | | 97.7 | 1.52 |
| S-L-1-13 | 0.86 | 20.20 | 20.38 | <10 | 165 | 0.95 | 30.76 | 46.81 | | | | | | 97.4 | 1.58 |
| S-L-1-23 | 5.48 | 19.22 | 20.33 | <10 | 159 | 0.96 | 30.07 | 45.02 | | | | | | 97.2 | 1.60 |
| S-L-2-02 | 7.61 | 18.91 | 20.47 | <10 | 157 | 0.42 | 28.77 | 43.62 | | | | | | 97.8 | 0.70 |
| S-L-2-13 | 6.81 | 18.99 | 20.38 | <10 | 171 | 0.90 | 29.27 | 44.07 | | | | | | 97.4 | 1.50 |
| S-L-2-23 | 7.37 | 18.77 | 20.26 | <10 | 184 | 1.13 | 29.80 | 44.44 | 0.54 | 0.17 | 0.12 | 0.30 | 0.08 | 96.8 | 1.88 |
| S-L-2-29 | 8.09 | 18.77 | 20.42 | <10 | 159 | 0.170 | 29.17 | 43.96 | 0.56 | 0.17 | 0.10 | 0.22 | 0.08 | 97.6 | 1.17 |
| Min | 0.86 | 18.77 | 20.12 | <10 | 148 | 0.42 | 28.77 | 43.52 | 0.53 | 0.14 | 0.10 | 0.22 | 0.07 | 96.1 | 0.70 |
| Max | 8.09 | 20.20 | 20.47 | 43 | 441 | 1.87 | 31.54 | 46.81 | 0.64 | 0.21 | 0.12 | 0.48 | 0.08 | 97.8 | 3.12 |
| Average | 5.93 | 19.14 | 20.35 | | 195 | 0.99 | 30.03 | 44.79 | 0.56 | 0.17 | 0.11 | 0.32 | 0.08 | 97.2 | 1.65 |
| Std. Dev. | 1.905 | 0.363 | 0.099 | | 72.3 | 0.371 | 0.817 | 0.962 | 0.036 | 0.020 | 0.007 | 0.084 | 0.004 | 0.47 | 0.62 |

## TABLE 4.8.2-3
## REPRODUCIBILITY OF CONTROLLED VARIABLES AND MEASURED PERFORMANCE FOR REPEAT TESTS

| | No Formic Acid | | | 400 ppm Formic Acid Tests | | | 800 ppm Formic Acid Tests | | |
|---|---|---|---|---|---|---|---|---|---|
| | Avg Value | Spooled | 95% conf. band | Avg Value . | Spooled | 95% conf. band | Avg Value . | Spooled | 95% conf. band |
| Fomic acid in Absorber Slurrv, ppm | 58 | 34 | ±73 | 462 | 78 | ±167 | 981 | 175 | ±375 |
| Absorber Pressure Drop, H20 | 1.21 | 0.048 | ±0.10 | 1.25 | 0.080 | ±0.17 | 1.16 | 0.033 | ±0.07 |
| NTU | 1.30 | 0.064 | ±0.13 | 2.10 | 0.097 | ±0.21 | 2.75 | 0.120 | ±0.26 |

## TABLE 4.8.2-4
## REPRODUCIBILITY OF MEASURED S02 REMOVAL FOR REPEAT TESTS

| $SO_2$ Removal Range % (absolute) | Pooled Standard Deviation, % (absolute) | Degrees of Freedom | $t_{95\%}$ | 95% Confidence Band, % (absolute) |
|---|---|---|---|---|
| >95 | 0.44 | 9 | 2.26 | ±1.0 |
| 90 to 95 | 0.71 | 10 | 2.23 | ±1.6 |
| 0 to 90 | 1.81 | 13 | 2.16 | ±3.9 |
| <70 | 2.30 | 9 | 2.26 | ±5.2 |

## TABLE 4.8.2-5
## REPRODUCIBILITY FOR UNCONTROLLED VARIABLES FOR REPEAT TESTS

| | No Formic Acid | | | 400 ppm Formic Acid Tests | | | 800 ppm Formic Acid Tests | | |
|---|---|---|---|---|---|---|---|---|---|
| | Avg Value | Spooled | 95% conf. band | Avg Value | Spooled | 95% conf. band | Avg Value. | Spooled | 95% conf. band |
| pH | 4.25 | 0.105 | ±0.23 | 4.09 | 0.049 | ±0.11 | 4.05 | 0.033 | ±0.07 |
| Gross Load, MW | 157.8 | 1.09 | ±-2.3 | 157.9 | 1.10 | ±2.4 | 157.1 | 1.24 | ±2.7 |
| Inlet Gas Flow, kacfm | 497 | 7.65 | ±16.4 | 488 | 10.11 | ±21.7 | 486 | 5.52 | ±11.8 |
| Inlet Gas Teniperature.$^{o}$F | 294 | 7.17 | ±15.4 | 301 | 6.90 | ±14.8 | 299 | 5.80 | ±12.4 |
| Inlet Gas $SO_2$ ppm | 1000 | 21.9 | ±47 | 970 | 93.8 | ±201 | 879 | 21.9 | ±47 |

### 4.8.3 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.

### 4.8.4 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.

### 4.8.5 FGD SYSTEM OPERABILITY AND RELIABILITY ISSUES

#### INTRODUCTION

This purpose of this section is to discuss the operating history of the FGD system with emphasis on ease of operation, frequency of process upsets, and ease of recovery from such upsets and specific problems encountered and solutions developed to eliminate them. The applicability of these solutions to commercial-scale installations using the technology is indicated and where the solutions are not applicable, recommendations are given for solutions in a commercial scale operation. Where problems arose which were not adequately solved, the further effort is needed to provide solutions is discussed together with any impact on commercialization. Other issues, such as performance stability and/or deterioration with time on stream are also addressed.

#### OPERATING HISTORY

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. During this period the Unit 2 absorber slurry stabilized at a pH level of 4.2 to 4.4, with solids content at 8 to 12%. The slurry chloride level reached 56,000 ppm, increasing at a rate of 2,000 ppm per week.

The Unit 1 FGD system first become operational on June 20, 1995.

#### July through September, 1995

Both generating units at Milliken Station operated at normal load conditions for the period the period from July through September, 1995. The FGD systems for both units were operated for the entire period. The brine concentrator began operation in July and experienced several operational and process related problems throughout the period. Toward the end of this period, Unit 2 was removed from service to complete a planned boiler inspection. This outage also allowed an inspection of the absorber module and some work to be completed on the heat pipe air heater.

The FGD systems performed well during the period. The average $SO_2$ removal for the period was in excess of 93% for both units. Similarly, the availability of both absorbers was in excess of 99%. The ability of the process to function efficiently at high chloride levels was demonstrated as well. The average chloride level in the modules for the period was 62,000 ppm, which is appreciably higher than what other absorbers are designed to operate at. Byproduct gypsum was sold to a wallboard manufacturer and to a cement company. The wastewater treatment system continued to operate as expected during this period. Approximately 630 tons of dewatered sludge were produced while consuming approximately 254 tons of lime.

The brine concentrator first become operational on July 20, 1995. The first shipment of calcium chloride was released on August 4, 1995. Laboratory analysis of a typical brine sample collected in August 1995 quantified the chemical composition as follows:

| | |
|---|---|
| calcium chloride | 32.61% |
| sodium chloride | 1.7% |
| potassium chloride | 0.14% |
| magnesium chloride | 0.13% |

Brine calcium chloride concentrations as high as 35% with comparable impurity levels have been produced at Milliken. Due to the confidential nature of NYSEG's brine marketing agreement, specific metals concentrations or further details concerning the calcium chloride are not available for publication.

The brine concentrator system experienced numerous operating problem during the period, as described below.

- Vibration: The vapor compressor experienced high vibrations in the high speed bearing area of the gear box during startups. This problem was first observed during the initial start of the system. While the system was ramping up in concentration levels, the compressor vibration levels would randomly spike high enough to cause a system shut down. The system was restarted several times and when the design brine concentration was reached, the vibration settled down and did not cause another trip.

- Chemistry: The feed to the brine concentrator was analyzed for chemical composition. The boron level was found to be appreciably higher than expected. Concentrations near 1,000 ppm were measured when the chloride level in the absorbers was approximately 70,000 ppm. The source of the boron was investigated. It was uncertain whether the high boron levels would be a significant factor in the long range operation of the brine concentrator system.

- Solids: After starting the brine concentrator the first time, the brine solution produced was not clear. A small amount of fine particles were carrying over from the product tank to the final storage tank. The product tank was designed to be a settling tank, but the particles were too small to be retained. This problem lasted for approximately four days after the initial start. The solids in the brine are unacceptable to the end user. Therefore, a portable filter press and additional storage tanks were rented to remove the solids and store the calcium chloride product. Problems with suspended solids in the brine product following system startup continued to be an issue.

- Plugging: During the normal operation of the brine concentrator, plugging was observed in the top of the distribution box. Solids were accumulating on top of the distributors which reduced the flow through the evaporator tubes. The progression of tube plugging was monitored through an inspection window located beneath the tubesheet which allows direct view of the flow from the tubes. Eventually, the reduced flow caused a compressor trip due to surge. It appears the plugging may have been caused by a solids control problem with the system. The seed recycle system designed to separate the suspended solids from the system did not perform well enough to maintain the design suspended solids in the concentrator.

- Corrosion: The vapor compressor suction expansion joint was originally manufactured from 316L stainless steel. The OEM replaced the joint with a Hastelloy joint. The original joint developed pin holes with less than four weeks operating time. The suction duct to the vapor compressor, also made of 316L stainless, was found to be pitting. The need to replace this duct with Hastelloy was identified.

The brine concentrator shut down on September 4, 1995 due to high vibration of the vapor compressor. With the brine concentrator off line the chloride concentration of the absorber slurry again began to increase beyond design levels. Authorization was received from NYSDEC to discharge the FGD blowdown pretreatment effluent to the Process Waste Water Reclamation Facility (PWRF). Discharge to the PWRF began on September 13, 1995, allowing the plant to begin reducing absorber slurry chloride.

### October through December of 1995

During the period from October through December of 1995 both generating units at Milliken Station operated at normal load conditions. Unit 2 was returned to service following a planned boiler inspection in October 1995. This outage also allowed an inspection of the absorber module and some work to be completed on the heat pipe air heater. The FGD systems for both units operated for the entire period.

The FGD systems performed well during the period. The average $SO_2$ removal was 90.1% and 83.6% for Units 1 and 2, respectively. The low sulfur coal testing completed during this period caused the removal rate for Unit 2 to be lowered. The availability of the absorbers was 97.4% and 99.5%. The average chloride levels in the modules for the period were 40,600 ppm and 45,000 ppm. Low sulfur coal testing was conducted on Unit 2 from October 11 through November 22, 1995. Newly designed pump suction liners were installed on four of the recycle slurry pumps.

The wastewater treatment system continued to operate as expected during the period. Approximately 803 tons of dewatered sludge were produced while consuming approximately 324 tons of lime.

The brine concentrator system continued to experience numerous operating problem during the period.

- Vibration: The vapor compressor continued to experience high vibrations in the high speed bearing area of the gear box during startups. This problem was first observed during the initial start of the system. While the system was ramping up in concentration levels, the compressor vibration levels would randomly spike high enough to cause a system shut down. The system was restarted several times and when the design brine concentration was reached, the vibration settled down and did not cause another trip.

- Chemistry: The boron level continued to be appreciably higher than expected. As the chloride level in the absorbers approached the normal operating level of 40,000 ppm, the boron level in the concentrator feed was reduced to approximately 500 ppm. The coal has been identified as the major source of the boron. It was uncertain whether the high boron levels would be a significant factor in the long range operation of the brine concentrator system.

- Solids: After starting the brine concentrator the first time, the brine solution produced was not clear. Problems with suspended solids in the brine product following system startup continued to be an issue.

- Plugging: During the normal operation of the brine concentrator, plugging continued to be observed in the top of the distribution box. Solids accumulated on top of the distributors which reduced the flow through the evaporator tubes. Eventually, the reduced flow causes a compressor trip due to surge. It appears the plugging may be caused by a solids control problem with the system. Ways to improve solids separation in the seed recycle system were being evaluated.

- Corrosion: The vapor compressor suction expansion joint was originally manufactured from 316L stainless steel. The OEM replaced the joint with a Hastelloy joint. During this period, corrosion was observed in the expansion joints in the discharge duct from the compressor. The joints were subsequently replaced with Hastelloy expansion joints. A new suction duct made of Hastelloy was scheduled for installation during 1996.

### January through March of 1996

Both generating units at Milliken Station operated at normal load conditions for the period. Unit 2 was removed from service from March 15, 1996 to April 3, 1996 to complete a planned boiler inspection. This outage allowed an inspection of the absorber module and some work to be completed on the heat pipe air heater. The FGD systems for both units operated for the entire period.

The FGD systems performed well during the period. The average $SO_2$ removal was in excess of 89% for both units. The availability of both absorbers was over 99%. The ability of the process to function efficiently at high chloride levels was demonstrated as well. The average chloride level in the modules for the period was 51,000 ppm, much higher than most absorbers are designed to operate at. During the March outage some broken spray nozzles were found and replaced in the Unit 2 absorber. The nozzles are made of a ceramic material which is resistant to abrasion but brittle.

The wastewater treatment system continued to operate as expected during the period. Approximately 752 tons of dewatered sludge were produced while consuming approximately 340 tons of lime. Performance testing of the wastewater treatment system was conducted between January 9 and 19, 1996.

The brine concentrator system continued to experience numerous operating problem during the period.

- Vibration: The vapor compressor continued to experience high vibrations in the high speed bearing area of the gear box. This problem was first observed during the initial start of the system. While the system was ramping up in concentration levels, the compressor vibration levels would randomly spike high enough to cause a system shut down. A back-pressure control valve was installed on the discharge line of the vapor compressor to minimize vibrational problems during unit start-ups. The system was restarted several times and when the design brine concentration was reached, the vibration settled down and did not cause another trip. A discharge control valve was installed on the vapor compressor discharge line in February, 1996. Regulating the discharge pressure with this valve enabled the machine to be started without this vibration problem.

- Chemistry: The boron level continued to be appreciably higher than expected. When the design chloride level of 40,000 ppm in the absorber was reached the boron level in the concentrator feed was in the 450 ppm range. The major source of boron appears to be coal with minor contributions coming from limestone and make-up water. It was uncertain whether the high boron levels would be a significant factor in the long range operation of the brine concentrator system.

- Solids: After starting the brine concentrator the first time, the brine solution produced was not clear. A portable filter press to remove the solids and additional storage tanks to store the calcium chloride product were rented.

- Plugging: During normal operation of the brine concentrator, plugging continued to be observed in the top of the distribution box. Solids accumulation on top of the distributors reduced the flow through the evaporator tubes. The progression of tube plugging was monitored through an inspection window located beneath the tubesheet which allows a direct view of the flow from the tubes. Eventually, the reduced flow would cause a compressor trip due to surge. It was postulated that a cause of the plugging may be inadequate control of suspended solids concentration in the recirculating brine. The seed recycle system designed to separate the suspended solids from the system was not performing well. The design concentration of suspended solids could not be maintained in the concentrator. The seed recycle system was re-piped in January to improve the separation of the solids in the hydrocyclone. This modification improved control of suspended solids concentration, but plugging of the brine concentrator and the associated compressor tripping problems persisted. The brine concentrator was operable for less than two weeks at a time. Efforts continued to enlist the support of research organizations with experience with gypsum particles and related process mechanisms.

Build-up of solids was also seen in the heat exchangers. This problem may have been caused by localized over-heating during the prolonged startup events. Performance of the heat exchangers must be monitored and the exchangers cleaned as needed. The heat exchanger plugging did not cause the system to become inoperable as the exchanger plates were inspected and cleaned during the frequent system outages. However, heat exchanger plugging was identified as a potentially limiting factor for prolonged system operation. The proper feed temperature to the evaporator is required to maintain the steaming capabilities on the tube side of the evaporator and the resulting steam supply to the compressor.

- Corrosion: The vapor compressor suction duct, originally manufactured from 316L stainless steel was replaced with a Hastelloy duct in February due to pitting corrosion. Pitting was observed on the vapor compressor inlet guide vanes and mechanism, on the high speed shaft, and to a lesser extent on the volute and casing. The pitting on the guide vanes was of special concern because a mechanical failure in this area could result in a failure of the entire machine. The need to monitor the condition of these components was identified. An investigation of their possible replacement was initiated.

**April through June 30, 1996**

Both generating units at Milliken Station operated at normal load conditions for the period. Unit 2 was returned to service on April 3 following the completion of a planned boiler inspection. This outage also allowed an inspection of the absorber module and some work to be completed on the heat pipe air heater. The FGD systems for both units operated for the entire period.

The absorber availability % calculation was changed to reflect the actual impact of the absorber on unit generating performance. Milliken Station operates both units through one module in order to conserve energy when on reduced load for extended periods. The absorber that is not in service during this time period is not unavailable.

The FGD systems performed well during the period. The average $SO_2$ removal for the period was in excess of 85% for both units. The design sulfur absorber testing was started in May with zero formic acid in the system. The removal efficiency for both absorbers was reduced due to the testing and the operation without formic acid. The testing was suspended due to the low levels of sulfur in the coal burned. The testing was to be resumed when an acceptable fuel supply could be obtained. The availability of both absorbers was 100%. The ability of the process to function efficiently at high chloride levels was demonstrated as well. The average chloride level in the modules for the period was 35,000 ppm.

During the Unit 2 March outage, some broken nozzles were found and replaced in the absorber. The nozzles are made of a ceramic material, which is resistant to abrasion but brittle.

The wastewater treatment system continued to operate as expected during the period. Approximately 349 tons of dewatered sludge were produced while consuming approximately 207 tons of lime.

The brine concentrator continued to experience numerous operating problems during the period. The system ran intermittently for short periods. NYSEG continued to work with the OEM and outside organizations in an attempt to resolve the operating problems.

- Solids, plugging and scaling: The plugging and scaling problems in the brine concentrator and heat exchangers persisted during this period as NYSEG prepared to enlist the support of research organizations with experience with gypsum particles and related process mechanisms.

- Corrosion: NYSEG continued to monitor the condition and to investigate the replacement of the vapor compressor components which showed evidence of pitting. In June, the vapor compressor experienced a failed set screw in the nose piece of the impeller. The set screw had corroded. The machine was disassembled and the high speed shaft and impeller were sent to the OEM for repairs.

**July through September, 1996**

Both generating units operated at normal load conditions for the period. Both units were in service for the entire period. The absorbers for both units were available for the entire period as well.

The FGD systems performed well during the period. The average $SO_2$ removal for the period was in excess of 85% for both units. The ability of the process to function efficiently at high chloride levels continued to be demonstrated. The average chloride level in the modules for the period was in excess of 45,000 ppm.

The wastewater treatment system continued to operate as expected during the period. Approximately 530 tons of dewatered sludge were produced while consuming approximately 272 tons of lime.

The brine concentrator continued to experience numerous operating problems during the period.

- Vibration: The brine concentrator was cleaned following a run in August that resulted in significant system plugging. The next attempt to restart the vapor compressor was unsuccessful due to a vibration on the high speed shaft of the machine. The cause of the vibration not known.

- Solids, plugging and scaling: The plugging and scaling problems in the brine concentrator and heat exchangers persisted during this period as NYSEG continued its efforts to enlist the support of research organizations with experience with gypsum particles and related process mechanisms.

- Corrosion: NYSEG continued to monitor the condition and to investigate the replacement of the vapor compressor components which showed evidence of pitting.

An FGD system condition assessment was made in August of 1996 with the following observations.

- The Stebbins tile on both modules performed well. No signs of abrasion on the tiles were observed. During startup, cracks developed on both modules that “self-healed” within a week. Three cracks on interior walls that did not progress through the module wall were repaired on the Unit 1 module. The cracks were through the center of adjoining tile. The repair was accomplished by grinding the crack and filling with an epoxy based mortar.

- The worst problem observed in the module was with the rubber on the turning vanes. Due to the combined cocurrent / countercurrent absorber module, a large set of rubber coated turning vanes was installed at the bottom of the countercurrent section. The rubber was installed as two layers of ¼ inch sheets. Some of the outer layer pealed off, causing partial plugging of recycle spray nozzles. The resulting flow restriction caused scale to form below the affected nozzles, plugging some of them completely. The rubber on the turning vanes in both modules was repaired by using the large doors in the bottom of the module to allow access with an electric lift.

- A problem with broken nozzles was also experienced. The recycle spray nozzles are flange mounted, pig-tail style and made of a ceramic material which is very brittle. The plant began experimenting with stainless steel and Stellite® nozzles.

- The mist eliminators performed well. Reducing the frequency of washing the top of the fine mist eliminator caused some plugging early on Unit 2. The plugged areas were power washed to remove build-up. The problem did not repeat after the mist eliminator wash frequency was re-adjusted.

- All pumps linings performed well. Some liners were replaced on the slurry bleed pumps due to erosion in the impeller clearance area. This appears to have been caused by foreign material being trapped in the pump. The mechanical seals performed well with the exception of the small pumps. Approximately four seals failed due to foreign objects getting caught in the seal area.

- Fiberglass piping held up well in all areas of service. One area on the centrifuge feed loop experienced excessive erosion downstream from a throttling valve. The piping was re-configured to eliminate the cause of the erosion. During construction there were times when the fabrications required modifications. The pipe was cut apart, refitted, glued and is now providing excellent service. Additional test ports required as part of the DOE demonstration testing were easily installed. The abrasion resistant lining in the heavier slurry lines showed no signs of wear. The same can be said of the spray headers with no wear shown on the outside from spray impingement or the inside. The rubber lined piping in the system showed no sign of wear.

- All rubber lined tanks performed well. Two failures were experienced on nozzle areas of the flake glass lined tanks. The failures appear to have been caused by a poor lining application. The module pH monitor was originally mounted in a flake glass lined vessel, which also experienced nozzle failures. The internal of the vessel was apparently too intricate to use flake glass lining. The pH tank was replaced with a PVC inverted U-tube and orifice plate.

- The primary and secondary hydrocyclones were installed with rubber apexes and vortex finders to facilitate field sizing. As expected, the rubber showed signs of abrasion particularly in the primary hydrocyclone apex. As originally planned the rubber apexes and vortex finders were replace with ceramic pieces. All other process related equipment including ball mills, centrifuges, oxidation blowers and valves performed well.

A sampling and analysis program to characterize process chemistry in support of brine concentrator operation was formalized (July/August '96).

During the first week in September, 1996, design sulfur coal testing was suspended due to some plugging of the recycle slurry spray nozzles.

### October through December, 1996

Both generating units at Milliken Station operated at normal load conditions for the period. Unit 1 was removed from service for one week in December to complete burner repair work. Unit 2 was removed from service for one week in October to complete a heat pipe air heater wash. The absorbers for both units were available for the entire period.

The ambient air monitoring program was completed at year end 1996 demonstrating that the Milliken CCTD project significantly reduced $SO_2$ and $NO_X$ concentrations in the immediate area.

The FGD systems performed well during the period. The average $SO_2$ removal for the period was in excess of 80% for both units. The mist eliminator performance tests on both absorbers were completed in October. The ability of the process to function efficiently at high chloride levels continued to be demonstrated. The average chloride level in the modules for the period was in excess of 39,000 ppm.

The Unit 2 FGD module was inspected and cleaned during a unit outage which was completed on October 18, 1996.

The Unit 1 FGD module was inspected and cleaned during a unit outage which began on November 9, 1996.

The wastewater treatment system continued to operate as expected during the period. The system produced approximately 667 tons of dewatered sludge while consuming approximately 206 tons of lime.

The brine concentrator did not operate during this period as numerous operating problems continued to be experienced with the system. From July through September plugging problems persisted in the brine concentrator. The system ran intermittently for short periods during the period. In September, the vapor compressor experienced a vibration problem. The machine was taken apart and the high speed shaft was removed to send to the OEM for inspection. The machine was reassembled in September and another vibration related problem was encountered during the ensuing system start up. The compressor was disassembled and the impeller was returned to the OEM for a detailed evaluation. A fit-up problem was discovered with the high speed shaft upon re-installation in November. The shaft was returned to the OEM for evaluation. NYSEG continued to work with the OEM and outside organizations in an attempt to resolve the operating problems.

**January through March, 1997**

Both generating units at Milliken Station operated at normal load conditions for the period. Unit 2 was removed from service for an annual boiler overhaul starting on March 31. The FGD systems for both units were available for the entire period.

The FGD systems performed well during the period. The average $SO_2$ removal for the period was in excess of 85% for both units. The ability of the process to function efficiently at high chloride levels continued to be demonstrated. The average chloride level in the modules for the period was in excess of 39,000 ppm.

The wastewater treatment system continued to operate as expected during the period. The system produced approximately 434 tons of dewatered sludge while consuming approximately 160 tons of lime.

The brine concentrator did not operate during this period as numerous operating problems continued to be experienced with the system. NYSEG continued to work with the OEM and outside organizations in an attempt to resolve the operating problems. In the interim, NYSEG received regulatory approval to temporarily discharge the pretreatment system effluent to the circulating water discharge. An application was submitted to NYSDEC to modify the Milliken SPDES permit to allow for discharge of the FGD blowdown pretreatment effluent to the circulating water system.

**April through June, 1997**

Both generating units at Milliken Station operated at normal load conditions for the period. Unit 2 was removed from service for an annual boiler overhaul starting on March 31.

The FGD systems performed well during the period. The average $SO_2$ removal for the period was in excess of 86% for both units. The average chloride level in the modules for the period was in excess of 30,000 ppm. The plant installed a new absorber spray nozzle design on the B header as well as a suction screen on one of the recycle slurry pumps during the Unit 2 outage (3/30 to 4/19/97).The unit was returned to service on April 20. The Unit 2 absorber was used to treat flue gas from both Units 1 and 2 to allow an inspection of the Unit 1 absorber for two days in April.

The wastewater treatment system continued to operate as expected during the period. The system produced approximately 501 tons of dewatered sludge while consuming approximately 137 tons of lime.

The brine concentrator did not operate during this period. NYSEG continued to work with the OEM and outside organizations in an attempt to resolve the operating problems.

### July through September, 1997

Both generating units at Milliken Station operated at normal load conditions for the period. Unit 1 was removed from service for an annual boiler overhaul from September 13 through October 4.

The FGD systems performed well during the period. The average $SO_2$ removal for the period was in excess of 79% for Unit 1 and 87% for Unit 2. The average chloride level in the modules for the period was in excess of 36,000 ppm. The Unit 1 FGD module was cleaned and inspected during the unit maintenance outage which began on September 13.

The wastewater treatment system continued to operate as expected during the period. The system produced approximately 521 tons of dewatered sludge while consuming approximately 139 tons of lime.

The brine concentrator did not operate during this period. NYSEG continued to work with the OEM and outside organizations in an attempt to resolve the operating problems. In August, the brine concentrator supplier provided revised operating conditions and sampling protocol for brine concentrator system. Plans were made to operate the system in the next quarter with different operating parameters in an attempt to improve system operability.

### October through December, 1997

Both generating units at Milliken Station operated at normal load conditions for the period. Unit 1 was returned to service from an annual boiler overhaul in October. Unit 2 was removed form service for an air heater wash in October.

The FGD systems performed well during the period. The average $SO_2$ removal for the period was in excess of 85% for Unit 1 and 79% for Unit 2. The average chloride level in the modules for the period was in excess of 34,000 ppm.

The wastewater treatment system continued to operate as expected during the period. The system produced approximately 600 tons of dewatered sludge while consuming approximately 113 tons of lime.

The brine concentrator was operated for ten days in December. The system was modified to operate with a different chemistry for the period. The system ran well mechanically. However, the brine produced appeared to crystallize at room temperature and the distillate had a low pH. The feed, brine, distillate and operating fluid from the run were sampled for analysis. Plans were made to evaluate the system's performance to determine its continued operation.

### January through March, 1998

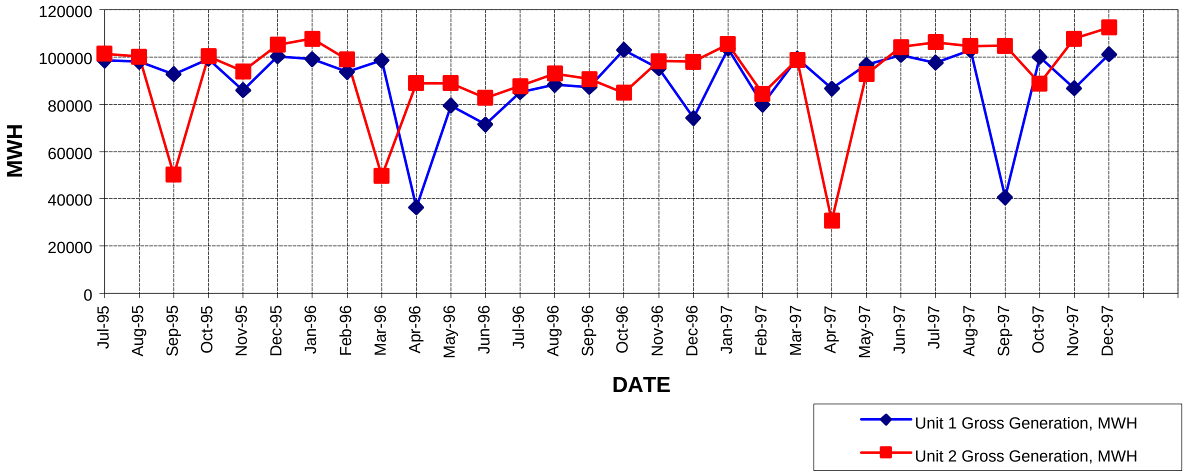
NYSEG and the brine concentrator system supplier reviewed current operating and chemistry issues on 3/19/98 and resolution of these issues is anticipated in the near future. Final determination as to the continued operation of brine concentrator system depends on the resolution of these issues.

## PERFORMANCE TRENDS

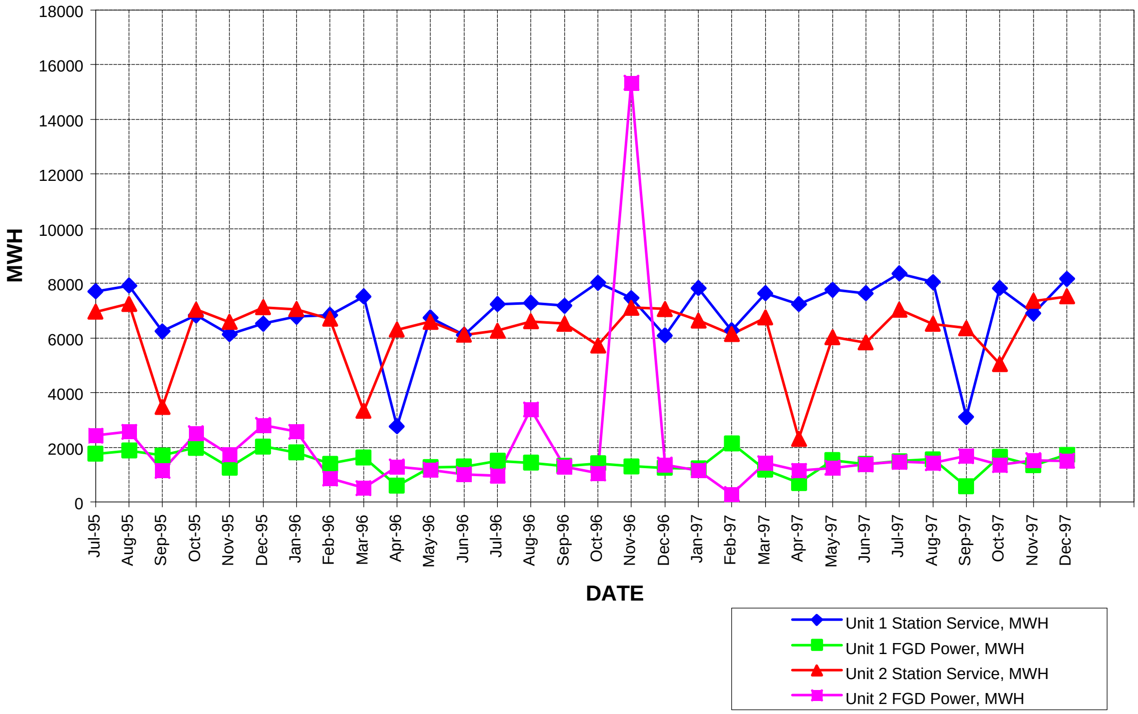
Beginning with the third quarter of 1995 the project Technical Progress Reports include tables of summary operating data for each Unit and for the station as a whole. Tables are included for each month in the quarter and for the entire quarter. These tables include data on gross and net generation, station service and FGD system power consumption, availabilities, capacity factors, thermal efficiencies, $NO_X$ emissions, fly ash quality, air heater performance, precipitator performance, fuel data, FGD system performance, and wastewater treatment system performance. Some of these variables are plotted vs. time in the following figures to illustrate system performance trends.

Figure 4.8.5-1 shows the gross power generation for both of the Milliken Units from July 1995 through December 1997, the last month for which data were available at the time of publication. Unit 2 gross generation tracks slightly higher than Unit 1 for this period. Figure 4.8.5-2 shows station service and FGD system power consumption for the same period. 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. Figure 4.8.5-3 shows the unit availabilities and capacity factors. Except for scheduled outages, unit availabilities held close to 100% and capacity factors generally held between 70% and 80% for the period. Figure 4.8.5-4 shows unit thermal efficiencies which hovered around 35% for both units. Figure 4.8.5-5 shows air heater exit temperatures with Unit 2 tracking a few degrees below Unit 1 for the period. Figure 4.8.5-6 shows $SO_2$ removal efficiencies for both units. Removal efficiencies showed no noticeable decline over the period, holding fairly constant at about 90%, except for periods of parametric testing. Figure 4.8.5-7 shows FGD system availabilities which have held fairly constant at close to 100%. By these measures the FGD system showed no performance deterioration nor adverse impacts on unit performance over the demonstration period.

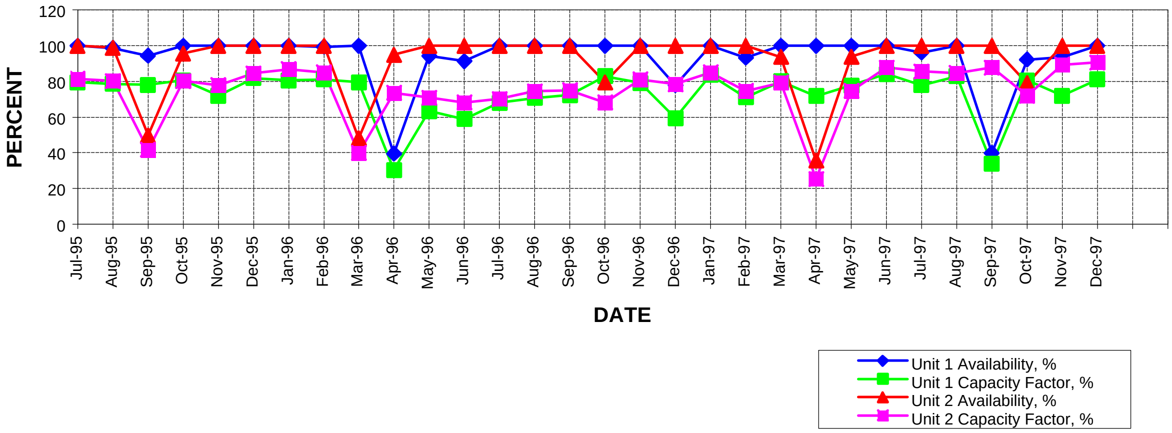
**FIGURE 4.8.5-1**
**GROSS GENERATION**



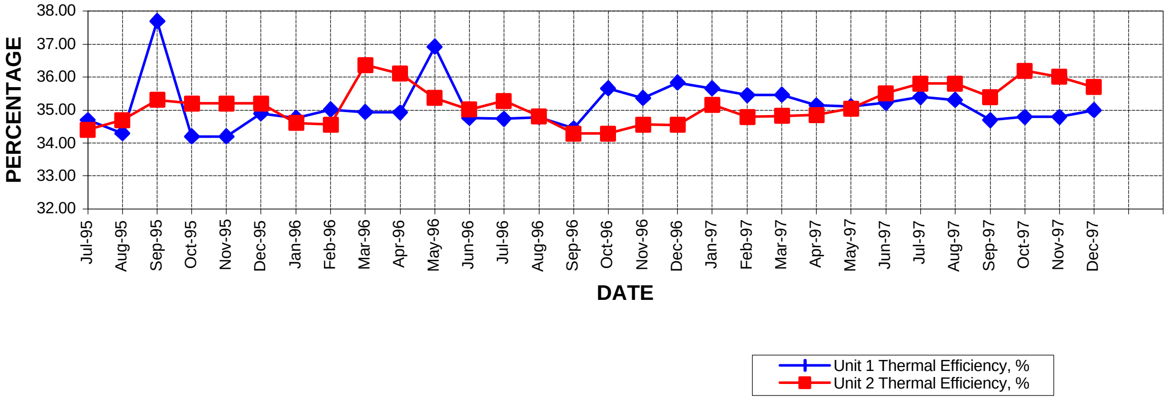
## FIGURE 4.8.5-2
## STATION SERVICE AND FGD SYSTEM POWER



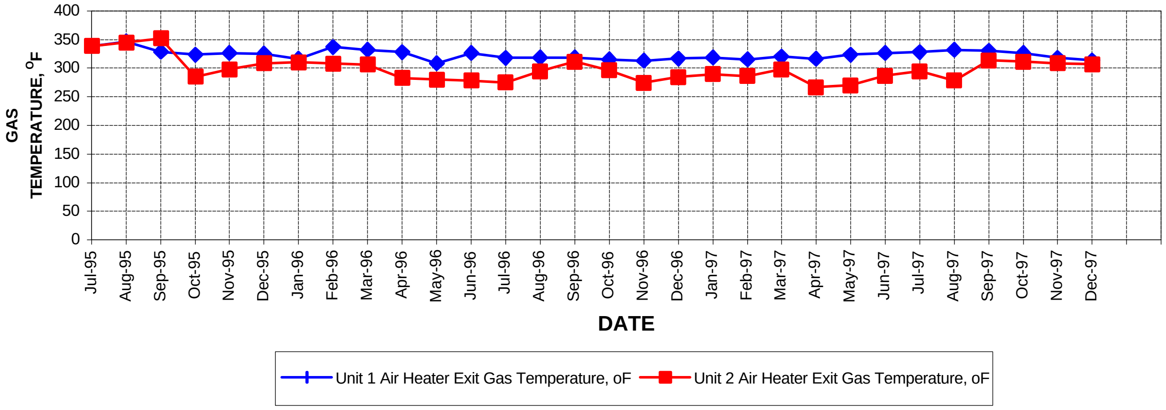
## FIGURE 4.8.5-3
## UNIT AVAILABILITY AND CAPACITY FACTOR



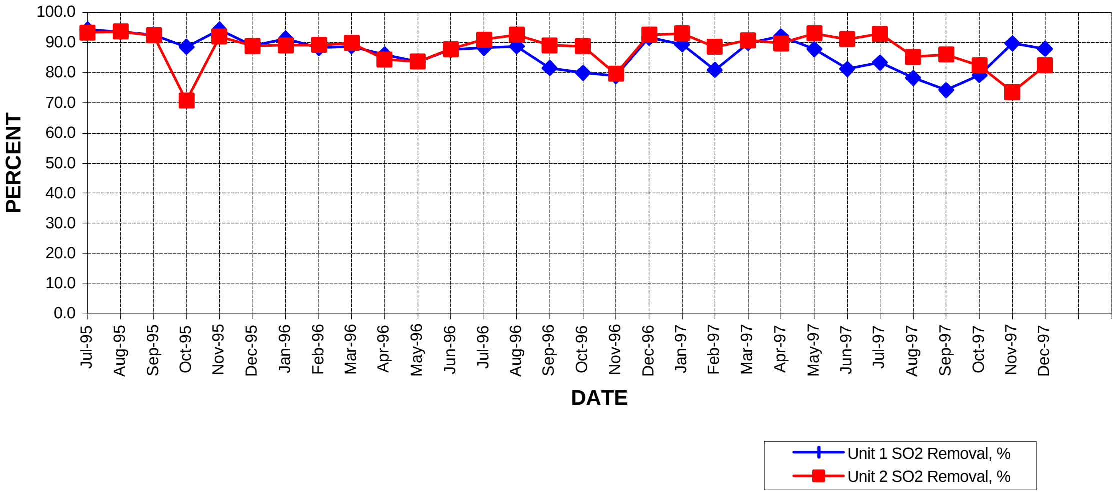
## FIGURE 4.8.5-4
## UNIT THERMAL EFFICIENCY



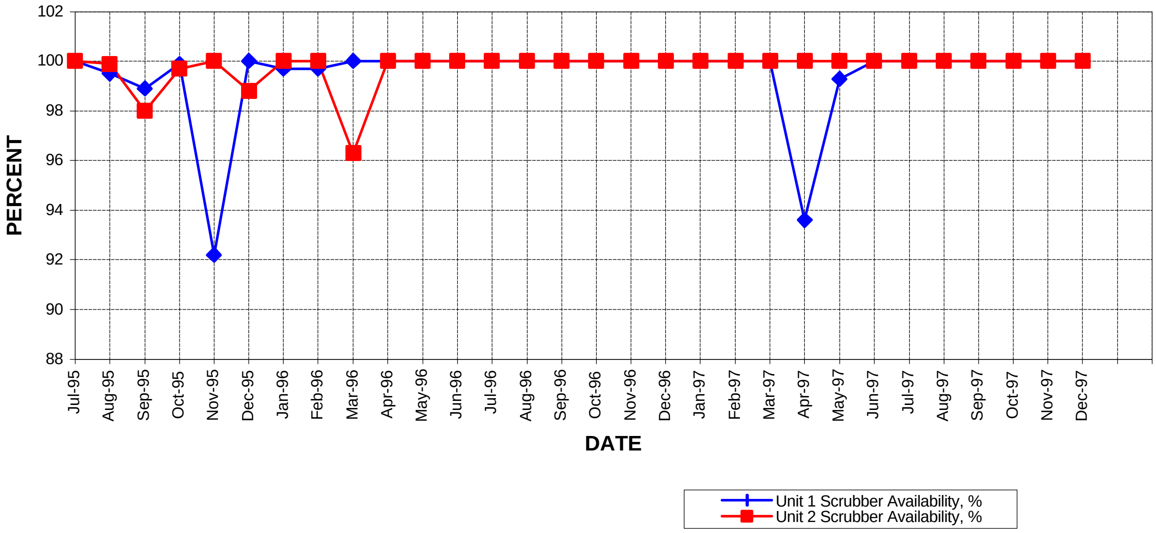
## FIGURE 4.8.5-5
## AIR HEATER EXIT GAS TEMPERATURE



## FIGURE 4.8.5-6
## UNIT $SO_2$ REMOVAL EFFICIENCY



## FIGURE 4.8.5-7
## FGD SYSTEM AVAILABILITY



## DISCUSSION OF OPERATING PROBLEMS

Both units started up in 1995 without problems and achieved the design 95% $SO_2$ removal efficiency within a few hours, with the boilers burning 1.8 - 2.2% sulfur coal. The units 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. Following is a summary of the specific problems encountered during this time and the solutions implemented.

- **Scaling and Plugging of FGD System Components**

  **Problem Description:** The absorbers have experienced a greater than expected deposit of solids on the absorber internals, slurry piping, and dewatering equipment. Upon inspection the scale on the absorber internals was found to be 1.5 inches thick. Extensive nozzle plugging occurs with both absorber modules. 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. Plugging has been most severe in the counter-current spray nozzles for Unit 1 and in the co-current spray nozzles for Unit 2. Plugging recurs in these nozzles within a few days after they have been cleaned. 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.

  **Causal Analysis:** There are several explanations of these phenomena.

  - The deposits are partially explained by the rubber loss and lack of recycle pump and gypsum bleed pump suction screens.

  - 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.

  - 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.

  - Finally, the absorbers were operated for a time with a substitute limestone reagent with high fluorides and high alumina. This limestone usage resulted in difficult to dewater gypsum due to a reduction in particle size. When this limestone usage was stopped and the original limestone was again added the particle size of the gypsum increased and the dewatering capability improved to the same as before substitution.

- In the dual module absorber configuration all of a module's agitators must be installed along a single wall not opposite the pump suctions. 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. The gypsum solids size distribution was found to be within specification limits. Agitator model testing falsely predicted adequate full scale solids suspension. Gypsum accumulates along the absorber wall opposite the agitators. In the Unit 1 module the accumulation would block the suction of Pump 100E (on the countercurrent side) if the pump were shut off. In the unit 2 module the accumulation would block the suction of Pump 200A (on the cocurrent side) if the pump were shut off. The accumulation reaches a height of 6 to 8 feet and extends 12 feet from the wall, an estimated 20 to 30 tons of material. As a consequence, the absorber recycle pumps in the settlement zones must be run continuously to keep their suctions from being blocked. The difference in plugging propensity between the cocurrent and countercurrent sides of the absorber modules has been attributed to the different slurry agitation patterns between the two modules. Though the two absorber modules are opposite hand, all of the absorber agitators have clockwise rotation. The rotation forces the slurry flow to the right of the agitator axis, creating a lower flow intensity zone to the left of the agitator axis. For Unit 1 the countercurrent side of the absorber module is to the left of the agitator axis. For Unit 2 the cocurrent side of the absorber module is to the left of the agitator axis. The heavier slurry particles tend to concentrate in the low flow intensity zones. These heavier (and larger) particles are drawn from the absorber sump by the recycle pumps and are forced into the spray headers associated with the low flow intensity zones, plugging the spray nozzles.

### Remedies

- **Slurry 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. Such screens are routinely used in SHU's European installations. Large pieces of gypsum that become dislodged as well as pieces of rubber from the pumps and other linings of tanks, or absorber internals, are able to pass through the recycle pumps to become lodged in the spray nozzles. In an effort to mitigate nozzle plugging a suction screen fabricated of perforated alloy plate was installed inside the Unit 2 absorber module in front of Pump 200E on the countercurrent side. The pump was run for 6 months during which the pump's spray nozzles did not plug and the pump discharge and suction pressures remained in their normal ranges. The screen was inspected during a boiler outage. Between 75% and 80% of the screen surface area was blocked with gypsum solids. Pieces of rubber were also found on the screen. A second screen was installed across the suction of Pump 100E on the countercurrent side of the Unit 1 absorber module and across the suction of the adjacent gypsum bleed pump 112A. After 2 months the pump motor amps remained steady in the normal range. Spray nozzle plugging problems were greatly reduced and the hydrocyclones currently operate without plugging. The plant plans to install screen for the remaining pumps.

Pump suction screens should be provided for future commercial installations of wet limestone FGD systems.

- **Absorber Agitators:** The absorber agitators, as originally designed, were not adequate to maintain gypsum slurry solids in suspension, resulting in significant accumulation of solids on the floor of the absorber sump. Increasing the agitator speed to the limit of the motor amperage (120 to 125 rpm) marginally improved operation but failed to remedy the problem. As a consequence, the absorber recycle pumps in the settlement zones must be run continuously to keep their suctions from being blocked.

  Absorber agitators should be more thoroughly tested and more conservatively sized in future commercial installations when applied to the dual module configuration.

- **Spray Nozzle Design**: The original design used ceramic spiral-type absorber spray nozzles. The nozzles are brittle and prone to breakage when being cleaned or if hit when other maintenance is being performed. In addition, replacement ceramic nozzles are expensive. A revised nozzle design was developed made of Stellite® with a suspended impingement cone. The new nozzles were installed on 200B header and were found to not plug as easily and to not break during cleaning. $SO_2$ removal efficiency is not noticeably affected. The plant plans to install these nozzles on 200A header and, if successful, on the remaining spray headers as dictated by wear and breakage.

  Spiral-type absorber spray nozzles have been used successfully in other SHU process installations. The difficulty with these nozzles at Milliken can be traced more to the absence of pump suction screens and the presence of unusually severe scaling conditions than to any inadequacy in nozzle design. Successful commercial installations of the SHU process could continue to use the spiral-type spray nozzles.

- **Slurry Density:** 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.

- **Reagent Short-Circuiting**

  **Problem Description:** 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 $SO_2$ 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.

  **Causal Analysis:** 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.

  **Remedy:** 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 $SO_2$ efficiency and gypsum quality, even higher $SO_2$ 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.

- **Centrifuge Feed Density**

  **Problem Description:** The original design called for operation of the 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.

  **Causal Analysis:** 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.

**Remedy:** The feed solids concentration was increased to 50%. Implementing this change required upgrading the centrifuge feed pump motors from 30 hp to 40 hp to handle the higher density slurry and increasing the solids concentration in the absorber reaction tank to an operating range of 10% to 14%. These changes 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.

- **Horizontal Slurry Pump Liner Wear:**

  **Problem Description:** 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.

  **Remedy:** 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.

- **Absorber Internal Turning Vane Lining**

  **Problem Description:** Rubber lining has peeled off from portions of the 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.

  **Causal Analysis:** 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.

  **Remedy:** 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.

- **Absorber Inlet Gas Flow Measurement**

  **Problem Description:** In order to achieve the required $SO_2$ removal the unit had to run with more recycle pumps on-line to increase the L/G ratio. The unit had difficulty following load swings and under-performed as regards $SO_2$ removal efficiency .

  **Causal Analysis:** 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 did not have the requisite straight run of duct work for accurate flow measurement, a layout compromise to simplify access and reduce platforming costs. The falsely low flow rate signals resulted in under-dosing of limestone. The pH trim control could not add enough limestone to compensate.

**Remedy:** 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.

- **Centrifuge Feed Valves**

  **Problem Description:** Knife gate valves are used to isolate the feed to the centrifuges. These valves cycle open and closed every 15 minutes. The high number of cycles has resulted in abrasion of the valve seal faces, making the valves difficult to close.

  **Remedy:** A different style of valve, such as a pinch valve, may be more appropriate for this application.

- **Stebbins Absorber Acid Brick Deterioration**

  **Problem Description:** The acid brick section of the absorbers in vicinity of the A & B Headers has shown some premature deterioration of a random sampling of bricks. Some gouges are as much as ¾” deep. This condition appears to be worsening with each inspection.

  **Causal Analysis:** The manufacturer’s initial assessment was, because of the very limited number of bricks which exhibited damage, that the damaged bricks were of faulty manufacture. As the number of damaged bricks has grown in subsequent inspections it is suspected that the problem may be more systemic. The plant continues to monitor this issue.

  **Remedy:** No action has been taken as of this report.

- **Brine Concentrator System**

  **Problem Description:** The brine concentrator system has experienced numerous operating problem throughout the demonstration.

  - Compressor Reverse Rotation: Upon shutdown the vapor compressor would rotate in reverse. The compressor labyrinth seals, shaft and front shaft bearings were damaged.

  - Compressor Vibration: The vapor compressor experienced high vibrations in the high speed bearing area of the gear box during startups. This problem was first observed during the initial start of the system. While the system was ramping up in concentration levels, the compressor vibration levels would randomly spike high enough to cause a system shut down. Upon returning the rotor to the compressor manufacturer it was found to be extremely out of balance. Deposits were observed on the vapor compressor blades. The mist pads were inspected with no apparent installation misfits.

- Chemistry: The boron level in the brine concentrator feed stream was found to be appreciably higher than expected. As the chloride level in the absorbers approached the normal operating level of 40,000 ppm, the boron level in the concentrator feed was reduced to approximately 500 ppm. The coal has been identified as the major source of the boron. This may or may not be a significant factor in the long range operation of the brine concentrator system.

- Solids: After starting the brine concentrator the first time, the brine solution produced was not clear. Problems with suspended solids in the brine product following system startup continue to be an issue.

- Scaling: 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.

- Corrosion: 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 which are also constructed of 316L stainless steel.

**Causal Analysis**

- Compressor Reverse Rotation: In the original design no back flow prevention was provided on the vapor compressor to prevent reverse rotation upon shutdown. During reverse rotation, the gear driven lube oil pump is rotated in reverse essentially stopping flow of lubrication to the compressor. Because there is a foot valve on the oil suction line in the oil reservoir, the low pressure flex hose on the suction of the oil pump is subjected to the full discharge pressure of the lube oil pump when the pump is operated in reverse. This high pressure caused the hose to overextend. The concern with damage to the compressor was related to lack of oil to the bearings.

- Compressor Vibration: 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.

- Chemistry: 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 he 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.

- Solids: The brine concentrator waste system is designed to maintain the brine total dissolved solids (TDS) at a low enough concentration to prevent the precipitation of secondary salts. The system is also designed to maintain an adequate concentration of recirculating calcium sulfate (seed crystals) in the brine to prevent tube scaling and plugging. The concentration of seed crystals is measured as total suspended solids (TSS). A batch blowdown scheme is used to control the brine TDS. This blowdown is processed through the seed recycle system to prevent the loss of the calcium sulfate seed crystals that are needed to prevent tube scaling. The seed recycle system consists of the seed recycle pump and seed hydrocyclone. Brine from the discharge of the recirculation pump is continuously circulated through the seed hydrocyclone by the seed recycle pump. Suspended solids (seed crystals) are centrifugally separated from the brine as it passes through the seed hydrocyclone. These solids are returned to the suction of the recirculation pump. The clarified brine from the seed hydrocyclone passes through a density cell and then is either returned to the discharge of the recirculation pump or is blown down to the product tank. The frequency of blowdown to the product tank is based on the TDS concentration sensed by the density cell. Batch blowdown is also used to control the brine TSS. Brine is blown down from the discharge of the recirculation pump directly to the product tank if necessary to reduce the TSS. Brine concentrator blowdown is collected in the product tank. The product tank is intended to function as a decant tank with suspended solids settling to the bottom. The sludge collected at the product tank bottom is batch transferred by the underflow pump to the FGD sludge holding tank for subsequent dewatering by the filter press. The overflow from the product tank is 33 wt% calcium chloride which flows by gravity to the brine storage tank for export. It appears that the hydrocyclone is not working as designed. 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 µm, as compared to the 20 µm hydrocyclone design basis. The gypsum particles are too small to be separated by the hydrocyclone and too small to adequately settle in the product tank, creating the milky overflow.

- Scaling: Scaling of the evaporator tubes was found to be due to precipitation of gypsum scale due to chemical imbalances in the system.
- Corrosion: The vapor compressor suction duct and the expansion joints in the suction and discharge ducts are 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.

**Remedies:**

- Compressor Reverse Rotation: A check valve was installed to prevent reverse rotation of the compressor.
- Compressor 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. No vibration problems were experienced during the 10-day trial run in December, 1997.
- Chemistry: 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.
- Solids: An additional process step has 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.
- Scaling: 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.
- Corrosion: The vapor compressor suction duct and the expansion joints in the vapor compressor suction and discharge ducts, originally constructed with 316L stainless steel have been replaced with Hastelloy C276 materials. It is likely that the compressor inlet guide vanes, also constructed of 316L stainless steel, will also be replaced with Hastelloy C276 or titanium alloy.

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.

## 4.9 MILLIKEN-MIST ELIMINATOR (INCLUDING WET STACK) TESTING

This program documented performance of FGD System’s full scale mist eliminators including measurements of pressure drop, gas velocity, carryover and droplet size distribution at design conditions and as a function of boiler load and recycle pumps in service. Also documented is the performance of the wet stack including measurements of gas velocity, liquid loading, droplet size distribution and analysis of stack drain composition as a function of boiler load and number of recycle pumps in service. The results of this test program can be found in detail in the study entitled “Droplet Testing at the New York State Electric & Gas Milliken Station” prepared by Southern Research Institute, and dated January 20, 1997. The complete report can be obtained by contacting the DOE. A summary of the Milliken-Mist Eliminator (Including Wet Stack) Testing Program is provided below.

### 4.9.1 INTRODUCTION

Southern Research Institute was contracted by the New York State Electric and Gas (NYSEG) to perform droplet carryover testing at NYSEG's Milliken Station located near Ithaca, New York. Milliken Station has two generating units, each with a nominal capacity of 150 MW. Each unit utilizes a single-module absorber for flue gas desulfurization. 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 primary entrainment separator on 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). A copy of the test plan for conducting these measurements is included as Appendix A of the Mist Eliminator test report.

The report provides a description of the testing and the results obtained. 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 results of the measurements are summarized in table 4.9-1.

### 4.9.2 MEASUREMENT METHODS

The VDA uses on-the-fly video image analysis to detect and measure the diameters of all in-focus droplets that are entirely within the field of view of the camera in each video frame. The camera operates at a frame rate of 60 frames per second. Illumination is provided by a 0.5 microsecond flash-duration strobe lamp that is synchronized to fire immediately before the start of each video frame. Counts of measured droplets are accumulated in 160 size bins. These size bins were each 33 µm wide as the system was configured for the Milliken tests. The size range spanned by the VDA system for the Milliken tests was thus 33 µm to 5280 µm.

The size of the volume in space in which droplets are measured by the VDA is set by two factors. The first is the focal length of the lens used for imaging the droplets as this sets the field width and height (10.4 mm by 8 mm in the configuration used for these tests). The second factor is the depth-of-focus, which varies with droplet size. A signal related to image sharpness is generated for each image on each video scan line that intercepts it. A discriminator threshold is set which uses this signal to reject images that are out of focus. For the Milliken tests, any image was rejected for which the measured size would have been in error by the greater of 33 µm or ten percent of its diameter. That is, the maximum error for droplets smaller than 330 µm was 33 µm while the maximum error for droplets larger than 330 µm was ten percent of the measured size. A calibration curve providing depth-of-focus versus droplet size is generated in the laboratory using glass beads and paint spots of known sizes mounted on microscope slides prior to departure for any test in which the VDA is to be used. This calibration is sensitive to the illumination intensity; consequently the signal level from the video camera is monitored continuously during operation of the VDA and the intensity is adjusted if it departs from the value used when doing the laboratory calibrations of the system. In addition, spot checks are made of the depth-of-focus at one or more selected sizes immediately before and after completion of each VDA measurement session to verify that the system operates as intended during each test. (A further description of the VDA system is provided in Appendix B of the Mist Eliminator test report.)

The VDA system measures the concentration at each traverse point independently. However, these concentrations must be weighted in proportion to the gas velocities at the traverse points to arrive at a concentration representative of the total flow through the duct. Also, in making measurements in vertical flow situations like those at Milliken, the net transport velocity of a droplet depends on its settling velocity as well as the local gas velocity. Consequently a velocity traverse of the duct must be made in conjunction with each droplet concentration traverse. The velocity measurements at Milliken were made using an "S-type" pitot equipped with an electronic micro-manometer. The flue gas compositions were not measured; instead, typical values for coal-fired power plant flue gases were used. The flue gas composition was used only for calculating the gas velocities in the ducts and the actual values used have only a very minor influence on the results of those calculations. (The calculated velocities would differ by less than one percent for any value of oxygen content over the range from 3% to 10%, provided corresponding changes were made in the carbon dioxide value to keep the sum of the two at about 19 to 20%.) The moisture content of the flue gas was taken to be the saturation value at the average temperature measured during each velocity traverse.

The VDA probe was used in a standard traverse pattern to measure droplet concentrations over the selected sampling planes with pitot measurements being made to provide gas velocities at each of the same traverse points. Three sets of droplet measurements of equal duration were made at each traverse point in the measurement plane at each location. The sampling durations used for each of the three sets of measurements at each sampling point were one minute at the mist eliminator (ME) inlet location, two minutes at the mist eliminator outlet locations, and three minutes at the stack locations. The data for each set of measurements are stored as an independent record in a computer file. Each record contains the number of droplets counted in each of the 160 individual size bins and an identifier for the traverse point at which that data set was obtained.

### 4.9.3 SAMPLING LOCATIONS

Measurements at Milliken were performed immediately above the exit planes of the second stage mist eliminators of the two modules. The total cross sectional area of each ME outlet is 770 square feet. However, structural steel beams running parallel to the direction of insertion of the VDA probe (below the level of the ports and centered between each port) reduced the effective cross section for flow at each outlet to 635.25 square feet. Similar steel beams located between the ports at the ME inlet sampling location reduced the flow cross section to the same value there as well. Measurements were made by introducing the probe through a series of four inch pipe sampling ports located along one wall of the tower into the vertically flowing gas streams.

At the outlets of the mist eliminators measurements were made at depths of 1.25, 3.75, 6.25, and 8.75 feet from the duct wall through each of four traverse ports. These ports were spaced at equal intervals along one 35-foot long side of the 22 by 35 foot tower cross section. The same pattern was to be used at the Unit 1 mist eliminator inlet. However, one of the ports at the inlet could not be used because the distance from the port to some structural steel opposite the port was too short to permit insertion of the VDA probe. At the stack locations sampling was done at the points appropriate for a standard twelve-point traverse of a round duct (6.2, 22.1, and 42.6 inches for the 12-foot diameter flues at Milliken). The test plan called for sampling in the stack at these depths for each of four ports at 90 degrees around each flue. In fact, there were only three ports on each stack, so measurements there were made at only nine of the planned twelve points.

### 4.9.4 TEST PROCEDURE

Four modifications were made to the test plan after arrival at the plant. The first modification was to adjust sampling duration at each traverse point. These adjustments were made to facilitate the expeditious completion of each test while still measuring a statistically significant number of droplets. The second modification was the omission of the port that was rendered inaccessible by the structural steel at the ME inlet. The third modification was the use of only three ports at the stack locations as a result of the planned fourth port not having been present. Finally, the high load test at the Unit 2 ME outlet was scheduled to be performed on the afternoon of September 30. Unfortunately, while preparing to perform this test the electronic micro-manometer needed for measuring the gas velocities above the mist eliminator was found to have failed.

Consequently that test was rescheduled for the end of the test program to follow the low load testing at the Unit 2 ME outlet. Velocity measurements at the crossover test conditions and at the stack did not require the micro-manometer and deferring the first test allowed time for a replacement to be sent while other tests were in progress. None of these changes in the test strategy made the measurements less representative in any significant way.

The VDA system calibrations were checked, adjusted if needed, and verified prior to the start of its use each day and were then rechecked to verify continued proper operation and calibration at the end of each day of measurement. The results of the calibration verifications were satisfactory in all cases.

A minimum of 10 minutes of warm-up time was allowed after the VDA probe was initially inserted into the duct to allow it to equilibrate at the flue gas temperature before starting to take data. A shorter time was allowed for equilibration after port moves unless the move took a relatively long time, as most moves could be completed before the probe had time to cool appreciably. The traverse of each port began at the maximum insertion depth and continued sequentially with the probe being withdrawn as required until the measurements nearest the duct wall had been taken. Three consecutive sets of measurements, each of equal duration, were taken at each traverse point during each traverse.

### 4.9.5 RESULTS AND DISCUSSION

A velocity traverse was made on each duct or flue either immediately before or after making the droplet concentration traverse on it. Complete results for each of the velocity traverses are provided in Appendix C of the Mist Eliminator test report. Because the whole of the sampling plane could not be measured during any of the traverses, cross-checks on how well emissions over the area sampled might represent the overall cross sections were desired. Two checks were used. First, total gas flows were calculated based on averages of the velocities measured over the sampling area. These were then compared to gas flows recorded by the plant's CEM systems. The results, included in table 4.9-1, showed excellent agreement for the most part, although the flows extrapolated from the traverses were slightly high in some cases. Secondly, emission rates of droplets in the stack flues were expected to be comparable to, or greater than, those measured at the corresponding ME exit planes, as any droplets produced by condensate being stripped from the walls of the flues would add to the carryover from the mist eliminators. Such was found to be the case. Thus both checks confirmed that the traverses yielded data representative of the whole of the flue gas streams.

The droplet data obtained in the stack for the Unit 2 absorber system operating in crossover mode was obtained in only one of the three ports. The VDA system was set up and ready to begin the Unit 2 crossover stack test at about 3 p.m. on October 1. However, at the first attempt to insert the VDA probe we found that only the first couple of inches of the six-inch deep nipple had the needed open diameter. The inner four inches had a 1/8 to 3/16 inch thick layer of the plastic (or resin) coating the inner circumference of the nipple, making the opening too small for the probe to pass through it. A check of the remaining ports on both flues revealed the same problem was present in all cases. By about 6 p.m. the plant had located someone to grind away the excess material and the process of enlarging the openings was underway. The first of the three ports on the Unit 2 flue was opened enough to be usable by about 9 p.m. and testing in that port was completed at 9:40 p.m. At 10 p.m. it was apparent that the second port would not be usable until midnight or later, at which time the NYSEG shift supervisor strongly suggested that testing cease for the night, saying that the crossover operation could be continued long enough to permit the remainder of the measurements at that condition the following morning. As things transpired, the condition could not be held long enough the following morning to permit additional testing at the crossover condition, so data at that condition were limited to what had been taken in the single port the previous night. The reported emission rate for this test was calculated by assuming that the average rate for the one port applied to the stack as a whole. No further difficulties were encountered during the remaining tests at the stack locations.

During the course of the testing in the stack it was observed that condensate on the walls of flues appeared to be flowing down the walls at the low load and high load test conditions. However, the condensate appeared to be flowing up the walls at the crossover test condition. This upward flow was presumed to be the result of high shear forces from the 100+ feet-per-second gas velocities in the flues during crossover operation. If the condensate was being driven up the flues as it appeared to have been, the actual droplet emissions from the tops of the flue during crossover operation would have been significantly greater than the values measured.

During the crossover testing at both the Unit 2 and Unit 1 ME outlet locations, we noted that major spikes in the emission rates were associated with the ME washes. Figures 4.9-1 through 4 show graphs of the measured total concentration of liquid contained in droplets versus time through several of the tests. It is estimated that 65% to 90% of the droplet carryover measured at the mist eliminator outlets was directly related to the wash events under all test conditions. It should be noted that the concentration data shown in the figures exaggerates the effects of wash events because it gives equal weights to the volumes of water contained in droplets of all sizes. Many of the larger droplets that contribute a great deal to the measured concentration contribute in smaller proportions to carryover because of their relatively high settling velocities. (The transport rate is the product of concentration and velocity and the net velocities of larger droplets are lower than those of smaller ones.)

Variations in droplet emission rates were also observed during the testing at the stack, and may have been the result of washes as well. However, at the stack longer averaging times were used, which would reduce the amplitude of the variations in the recorded data. Also, the emissions measured at the stack would have come from less well-defined areas of the mist eliminators than those measured immediately above ME outlets. The combined temporal and spatial averaging at the stack as compared to the ME outlet negated the value of attempting to remove the effects of washes in the stack data.

Three major difficulties were experienced in the testing at the Unit 1 mist eliminator inlet. Measurements were made in the crossover operating mode on Saturday, October 5. As mentioned previously, access to one sampling port was blocked by the structural steel so sampling could be done through only three of the four ports. Secondly, attempts to make velocity measurements at the ME inlet on that date and on Monday, October 7 (when the remainder of the ME inlet tests were performed) were stymied by overwhelming amounts of water in the gas stream. In places the video from the VDA gave one the impression that it was located under a waterfall and, in a sense, it may well have been. If the sketch of the layout that was provided us after the test is accurate, the line along which the traverses were made for each of the inlet ports was located directly under a valley in the primary entrainment separator, from which large amounts of water may have been draining. On two occasions when attempting to make measurements at a particularly bad location in this regard, the VDA probe had to be removed so that the windows and shrouds could be drained and cleaned because of virtually immediate "flooding" of one of the shrouds and windows. Further difficulties were created by the mist eliminator wash sprays, which produced droplets with enough horizontal velocity that the VDA shrouds and purge air were unable to keep them from reaching the illuminator and camera windows. This made frequent removal of the probe to clean the windows necessary and severely limited the amount of data that could be collected each time the probe was inserted. Discussions were held with the plant operating personnel regarding turning the wash systems off for long enough periods to traverse each port, but the operators on duty at the time lacked the authority to do so. As a consequence, the number of traverse points actually used during the inlet crossover test was less than called for by the test plan. However, data were obtained at enough locations that the resulting carryup rate is believed to be reasonably accurate barring errors for one additional complication.

ME outlet carryover and inlet carryup rates are calculated under the assumption that the net vertical velocity of a droplet is the difference between the local gas velocity and the settling velocity of the droplet. Although this can be expected to be true for droplets carried up from the absorber, it is clearly not the case for droplets produced by the wash sprays. The latter are ejected from the spray nozzles with much higher velocities than the local gas velocity and have too short a distance to travel to slow appreciably. Thus, the wash spray droplets have velocities that are far greater than the calculated net velocities (the gas velocity less the settling velocity) used in the data analysis. As a consequence, the calculated carryup rate for the crossover test condition at the inlet may significantly underestimate the true total rate at which liquid is conveyed to the ME because of the inability to properly account for the effect of the washes. On the other hand, the measured rates will include some part of the true rate from the washes and will thus be high when compared to the rates from the absorber sprays alone.

Only the inlet test under the crossover operating condition had the wash spray flooding problem. Arrangements were made to turn the wash sprays off during the traverses of each port when the other two ME inlet tests were conducted. With the wash sprays turned off, it was possible to make complete traverses through each of the three usable ports at the ME inlet for both the low-load and high-load test conditions. The calculated carryup rates for the ME inlet low-load and high-load tests thus represent the contribution from the absorber sprays but do not include the effects of washes. The inlet carryup rates were calculated using the velocities measured at the ME outlet at the corresponding points and test conditions because of problems experienced in trying to make velocity measurements at the inlet itself. How closely the ME inlet and outlet velocity distributions match is open to conjecture, but they are probably close enough to make the calculated carryup rates reasonably realistic.

ME efficiencies were calculated from the inlet carryup rates and ME carryover rates in two ways. First the two rates were compared directly. In this case, the contributions from the washes are included in the ME outlet rates but were not included in the inlet rates for the low-load and high-load test conditions and only partially accounted for in the crossover condition inlet results. In the second set of calculations the data from the periods in which the washes appeared to be contributing heavily to the carryover were dropped, allowing "wash off' outlet data to be compared to the inlet data. This results in calculated efficiencies that truly represent the fundamental performance of the mist eliminators for the low-load and high-load tests. However, because some part of the wash contribution was included in the inlet data for the crossover condition, the efficiencies in this manner for that condition are undoubtedly higher than the true value. The Unit 1 ME inlet data were taken to be representative of that for Unit 2 (for which inlet testing was not done) in the ME efficiency calculations for Unit 2.

The results of the individual VDA traverses are summarized in Figures 4.9-5 through 24 in terms of inlet carryup and outlet carryover rates by droplet size and size distributions on cumulative percentage by volume basis. Details of the results for each test are provided in tabular form in Tables 2 through 16 in the Mist Eliminator test report.

### 4.9.6 CONCLUSIONS

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.

TABLE 4.9-1. SUMMARY OF RESULTS FROM MILLIKEN DROPLET TESTING, 10/01196 - 10/09/96

| Date | Unit | Test Location | Test Condition | Gas Flow from Traverse, kdscfm | Gas Flow from Plant kscfm | Stack Drain Rate gpm | VDA Droplet Rate gpm | Mass Median Diameter μm | ME Eff. with Washes % | VDA Rate w/o Washes gpm | ME Eff. w/o Washes % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 10/1 | 2 | ME Outlet | Crossover | 514 | 514 | 0.56 | 3.1 | 600 | 99.21 | 0.574 | 99.85 |
|  | 2 | Stack | Crossover | 520 | 509 | 0.54 | 4.0 | 490 |  |  |  |
| 10/2 | 2 | Stack | Low Load | 275 | 270 | 1.16 | 0.06 | 300 |  |  |  |
|  | 2 | Stack | High Load | 310 | 306 | 0.91 | 0.58 | 670 |  |  |  |
| 10/3 | 1 | Stack | Low Load | 314 | 308 | 0.77 | 0.32 | 850 |  |  |  |
|  | 1 | Stack | High Load | 374 | 355 | NA | 0.43 | 650 |  |  |  |
| 10/4 | 1 | Stack | Crossover | 556 | 517 | NA | 0.16 | 600 | 99.952 | 0.017 | 99.9956 |
|  | 1 | ME Outlet | Crossover | 552 | 523 | 0.10 | 0.19 | 690 |  |  |  |
| 10/5 | 1 | ME Inlet | Crossover | (washes on) |  | NA | 386 | 880 |  |  |  |
| 10/7 | 1 | ME Inlet | Low Load | (washes off) |  | NA | 32 | 520 |  |  |  |
|  | 1 | ME Inlet | High Load | (washes off) |  | NA | 74 | 600 |  |  |  |
| 10/8 | 1 | ME Outlet | Low Load | 312 | 290 | 0.30 | 0.018 | 230 | 99.944 | 0.0027 | 99.9915 |
|  | 1 | ME Outlet | High Load | 356 | 348 | 0.10 | 0.057 | 230 | 99.923 | 0.0060 | 99.9919 |
| 10/9 | 2 | ME Outlet | Low Load | 287 | 290 | 1.27 | 0.015 | 410 | 99.953 | 0.0045 | 99.986 |
|  | 2 | ME Outlet | High Load | 325 | 325 | 0.53 | 0.015 | 400 | 99.979 | 0.0052 | 99.9930 |

## FIGURE 4.9-1

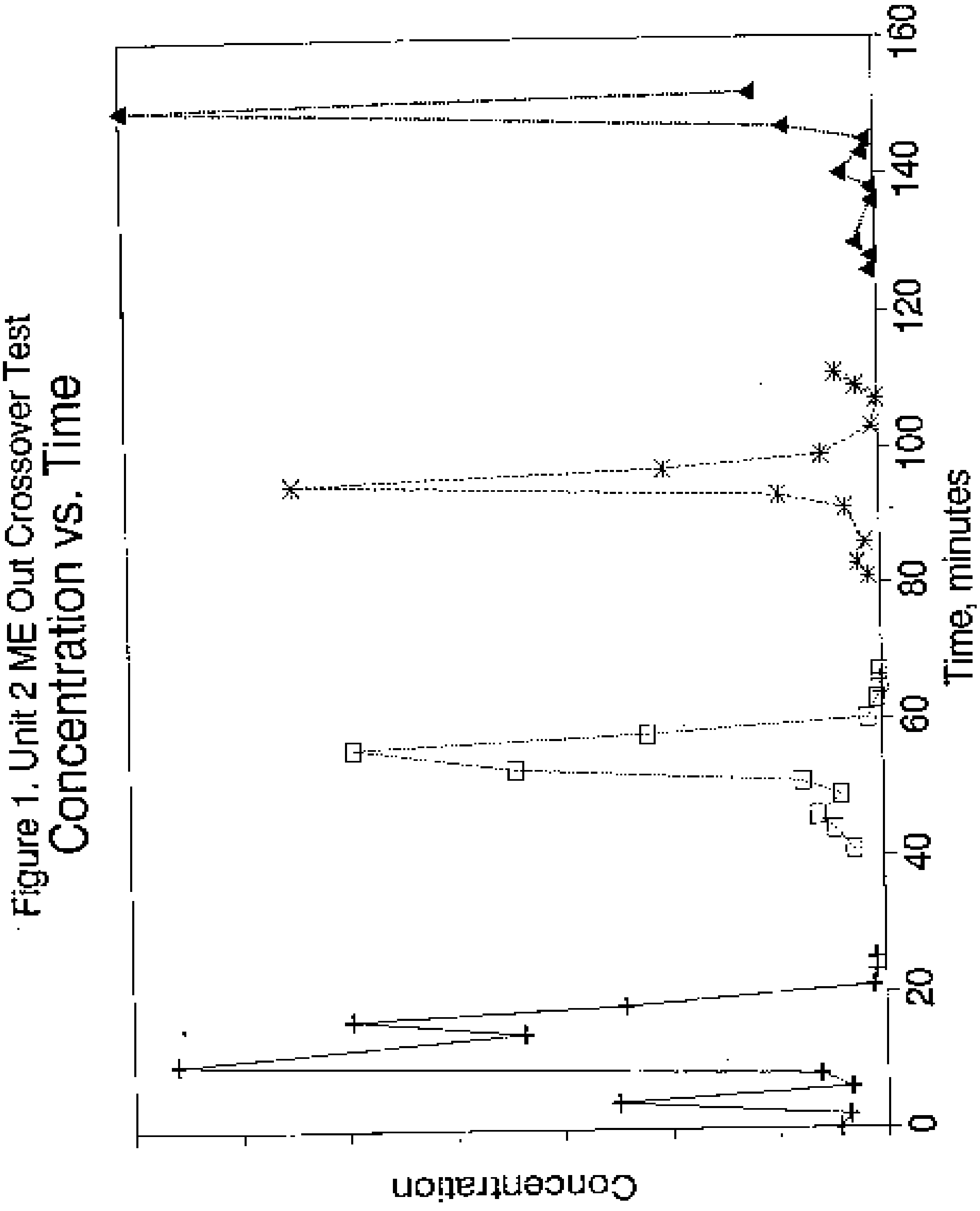


Figure 1. Unit 2 ME Out Crossover Test
Concentration vs. Time
Concentration
Time, minutes
0
20
40
60
80
100
120
140
160

**FIGURE 4.9-2**

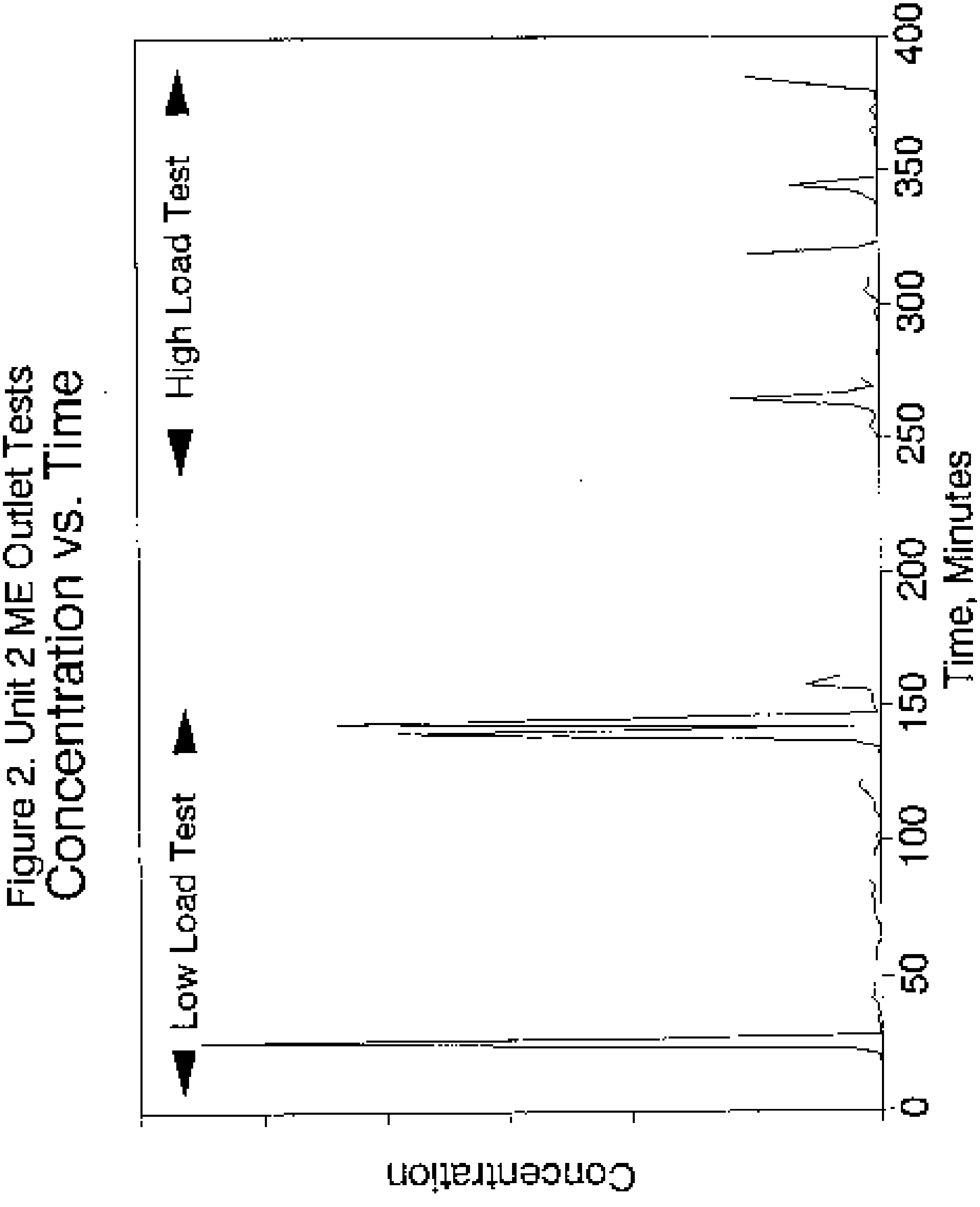


Figure 2. Unit 2 ME Outlet Tests
Concentration vs. Time

**FIGURE 4.9-3**

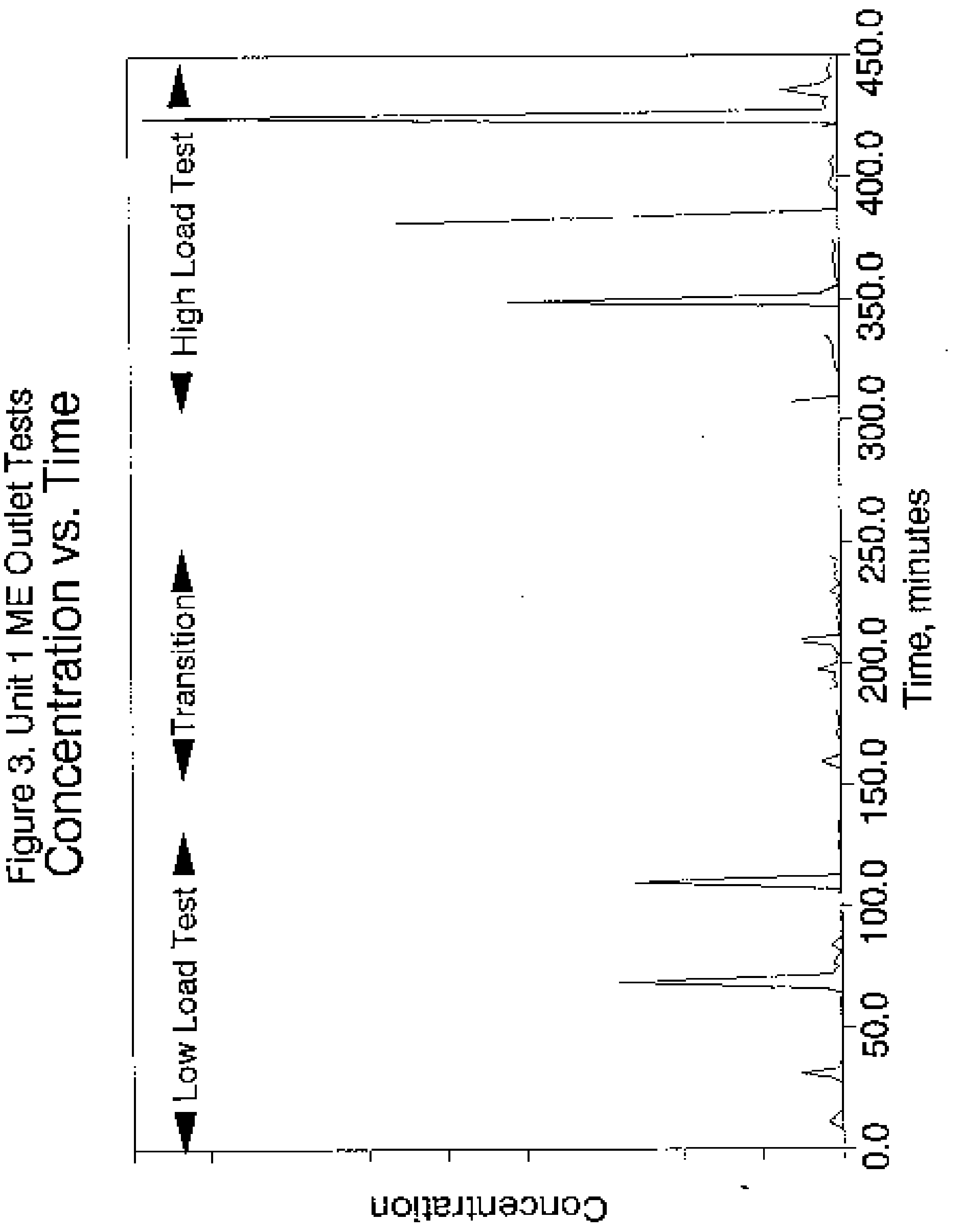


Figure 3. Unit 1 ME Outlet Tests
Concentration vs. Time
Low Load Test
Transition
High Load Test
0.0
50.0
100.0
150.0
200.0
250.0
300.0
350.0
400.0
450.0
Time, minutes
Concentration

**FIGURE 4.9-4**

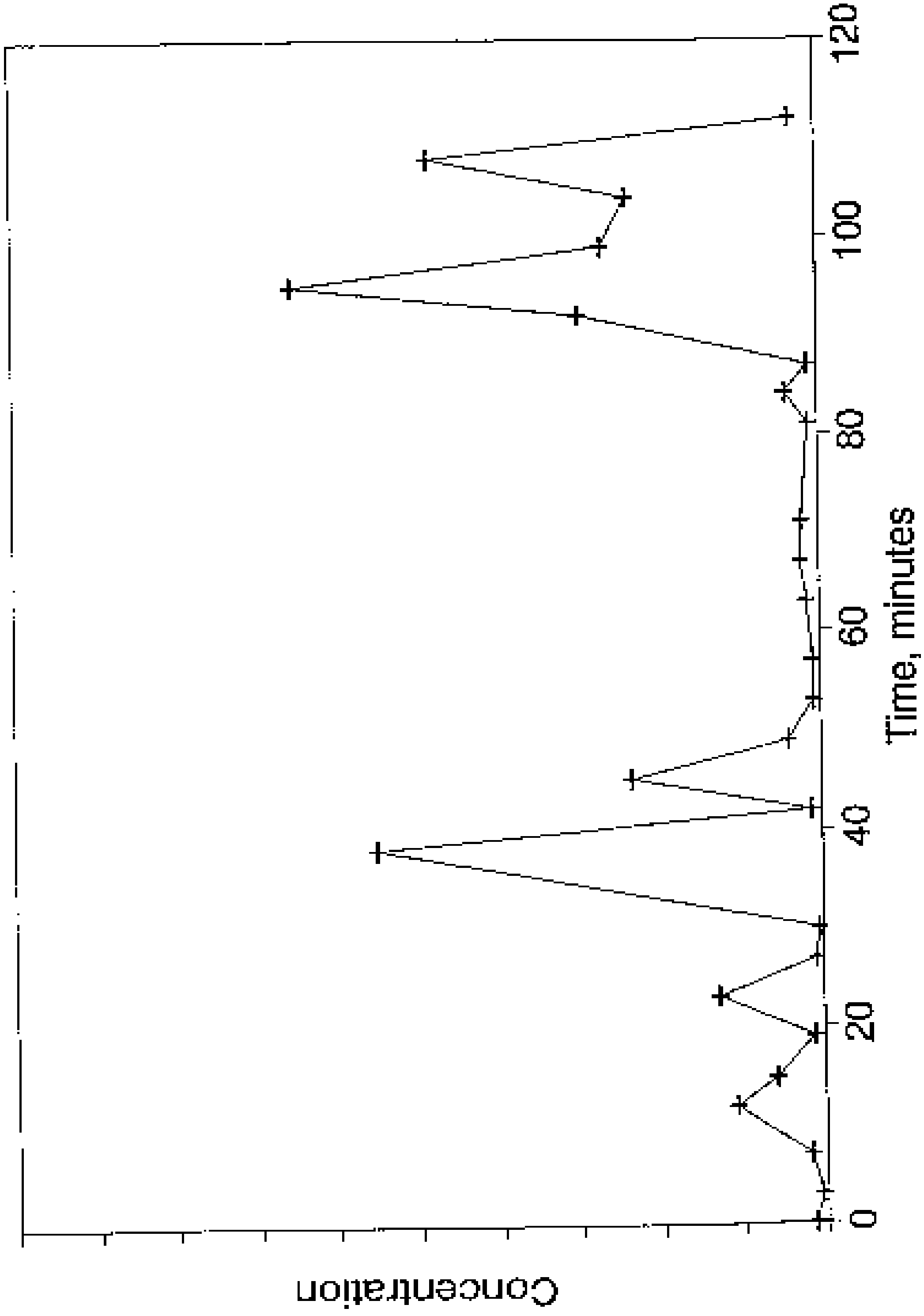


Figure 4. Unit 2 Stack at Low Load
Concentration vs. Time

## FIGURE 4.9-5

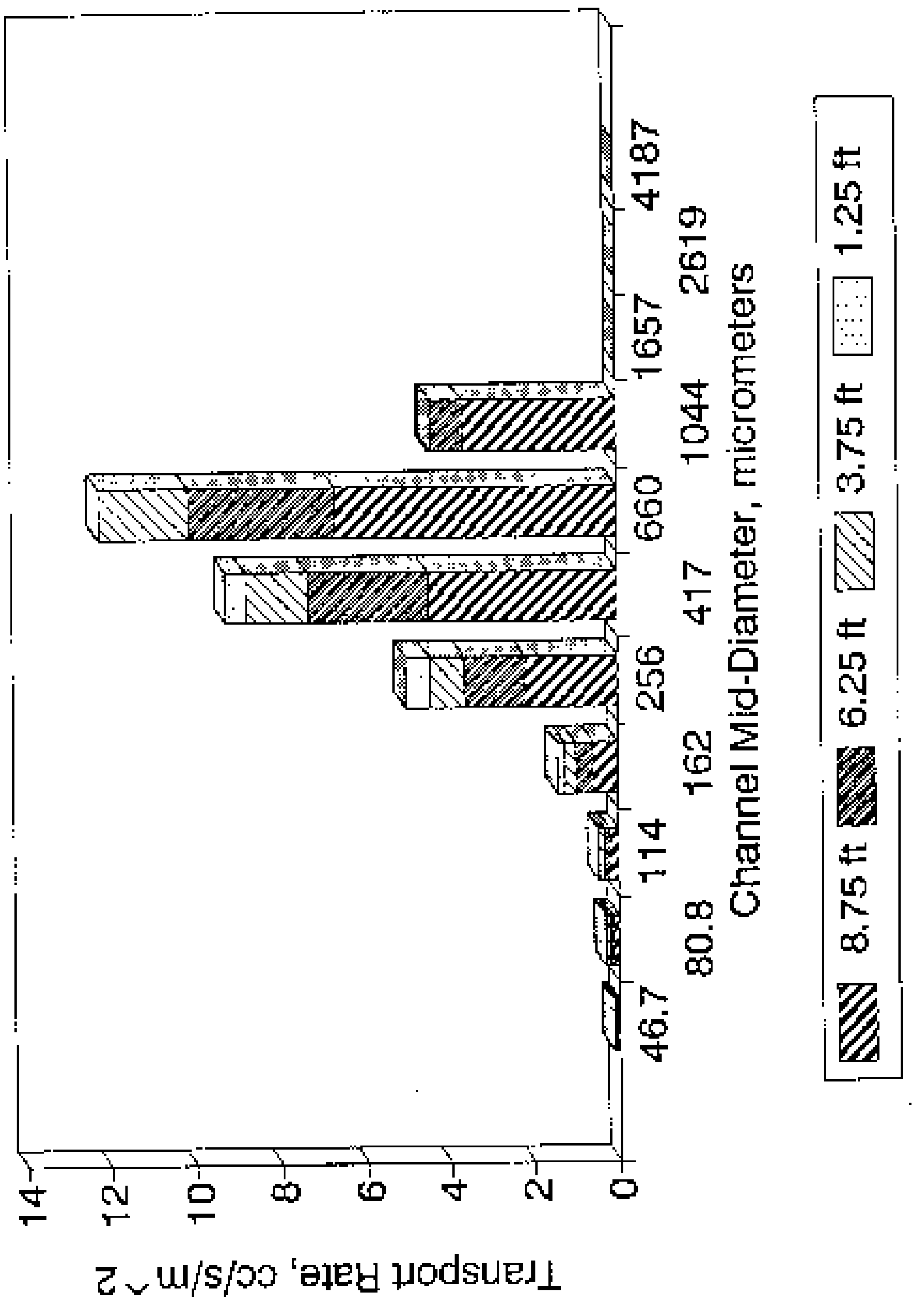


Figure 5. Unit 1 ME Inlet Low Load Test Carryup vs. Drop Size and Depth in Duct

**FIGURE 4.9-6**

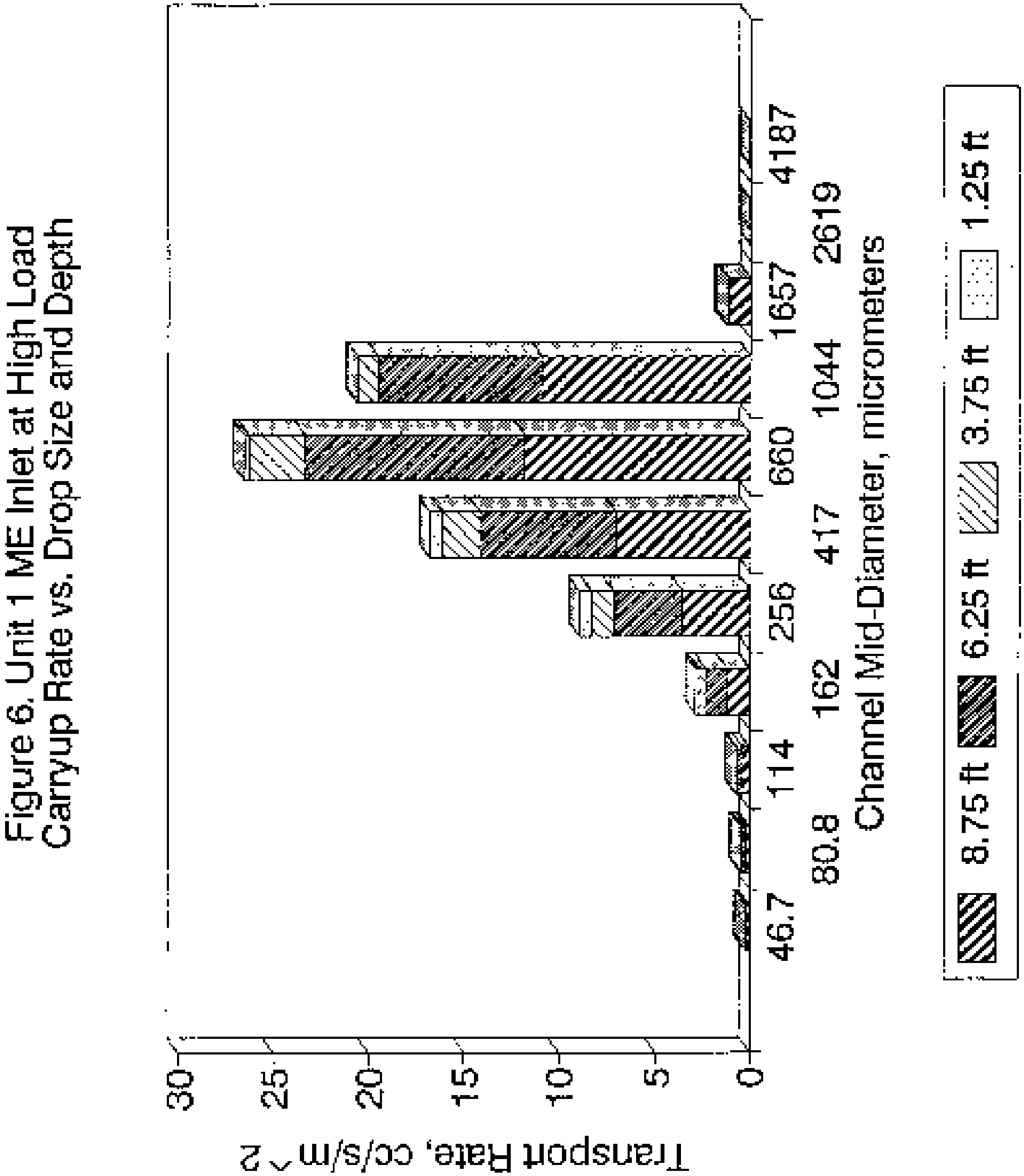


Figure 6. Unit 1 ME Inlet at High Load
Carryup Rate vs. Drop Size and Depth
Transport Rate, cc/s/m^2
0
5
10
15
20
25
30
46.7
80.8
114
162
256
417
660
1044
1657
2619
4187
Channel Mid-Diameter, micrometers
8.75 ft
6.25 ft
3.75 ft
1.25 ft

## FIGURE 4.9-7

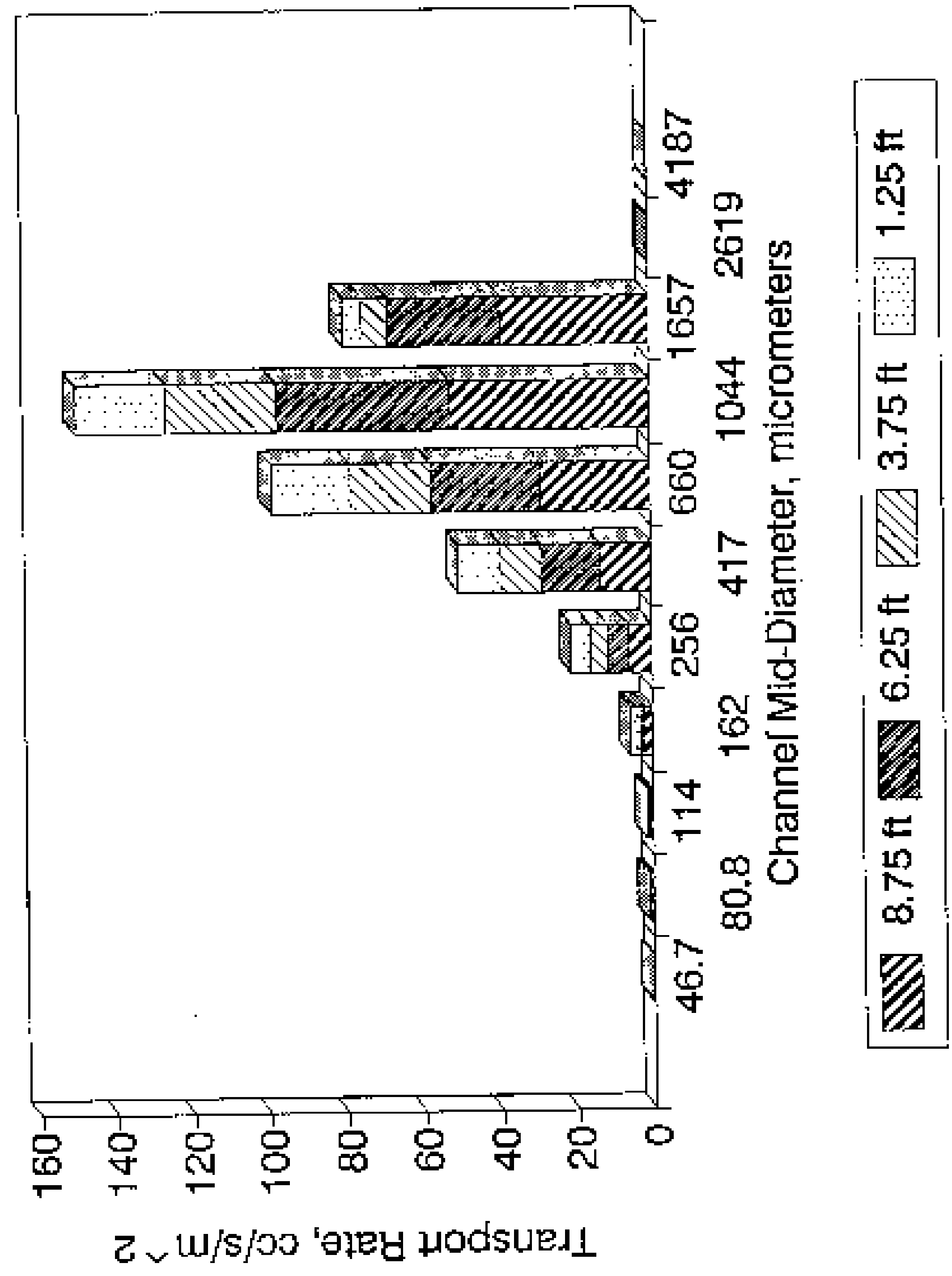


Figure 7. Unit 1 ME Inlet at Crossover Carryup Rate vs. Drop Size and Depth

**FIGURE 4.9-8**

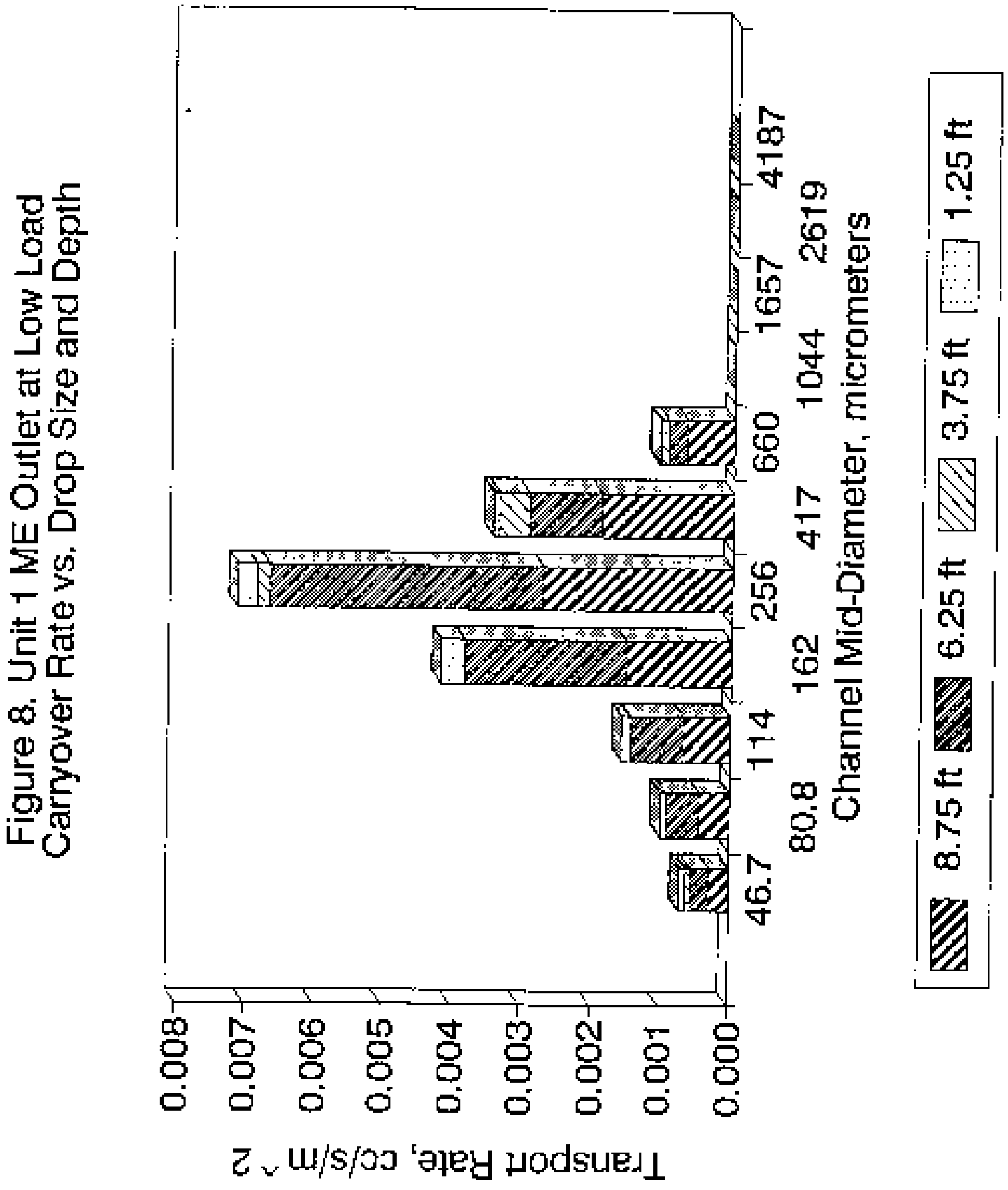


Figure 8. Unit 1 ME Outlet at Low Load
Carryover Rate vs. Drop Size and Depth
Transport Rate, cc/s/m ^ 2
0.000
0.001
0.002
0.003
0.004
0.005
0.006
0.007
0.008
46.7
80.8
114
162
256
417
660
1044
1657
2619
4187
Channel Mid-Diameter, micrometers
8.75 ft
6.25 ft
3.75 ft
1.25 ft

**FIGURE 4.9-9**

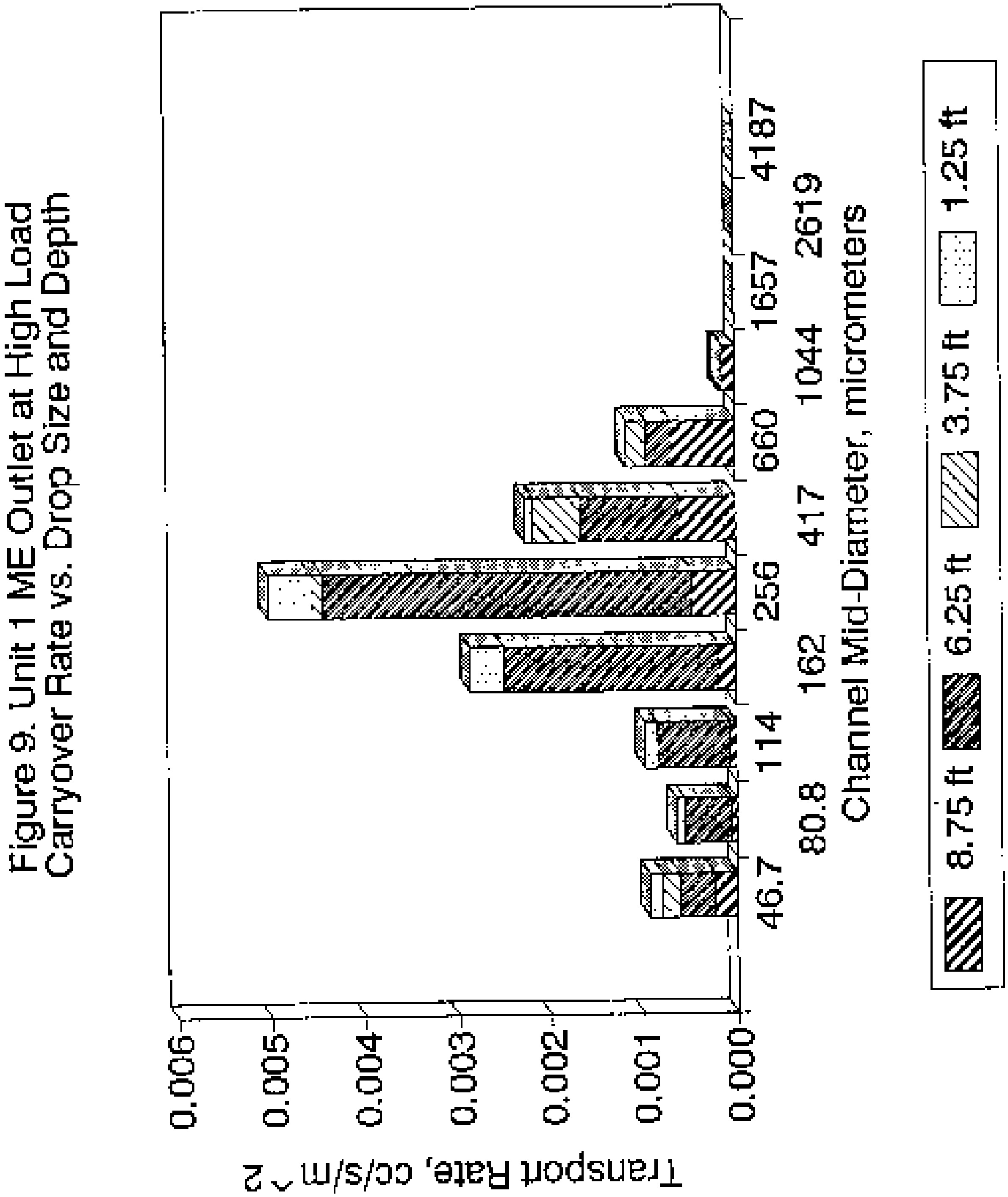


Figure 9. Unit 1 ME Outlet at High Load Carryover Rate vs. Drop Size and Depth

**FIGURE 4.9-10**

Figure 10. Unit 1 ME Out at Crossover Carryover Rate vs. Drop Size and Depth

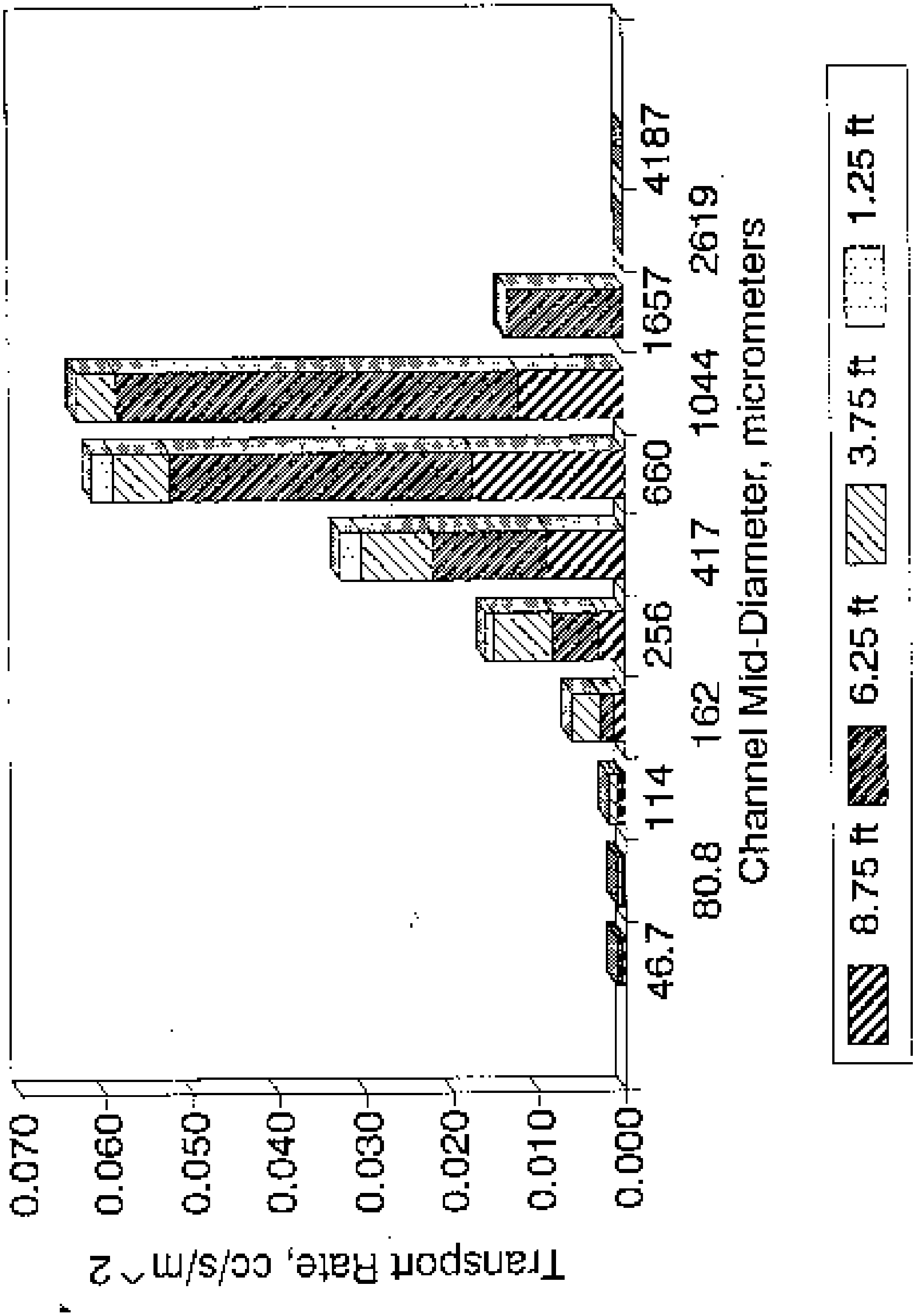


**FIGURE 4.9-11**

Figure 11. Unit 1 Stack at Low Load Carryover Rate vs. Drop Size and Depth

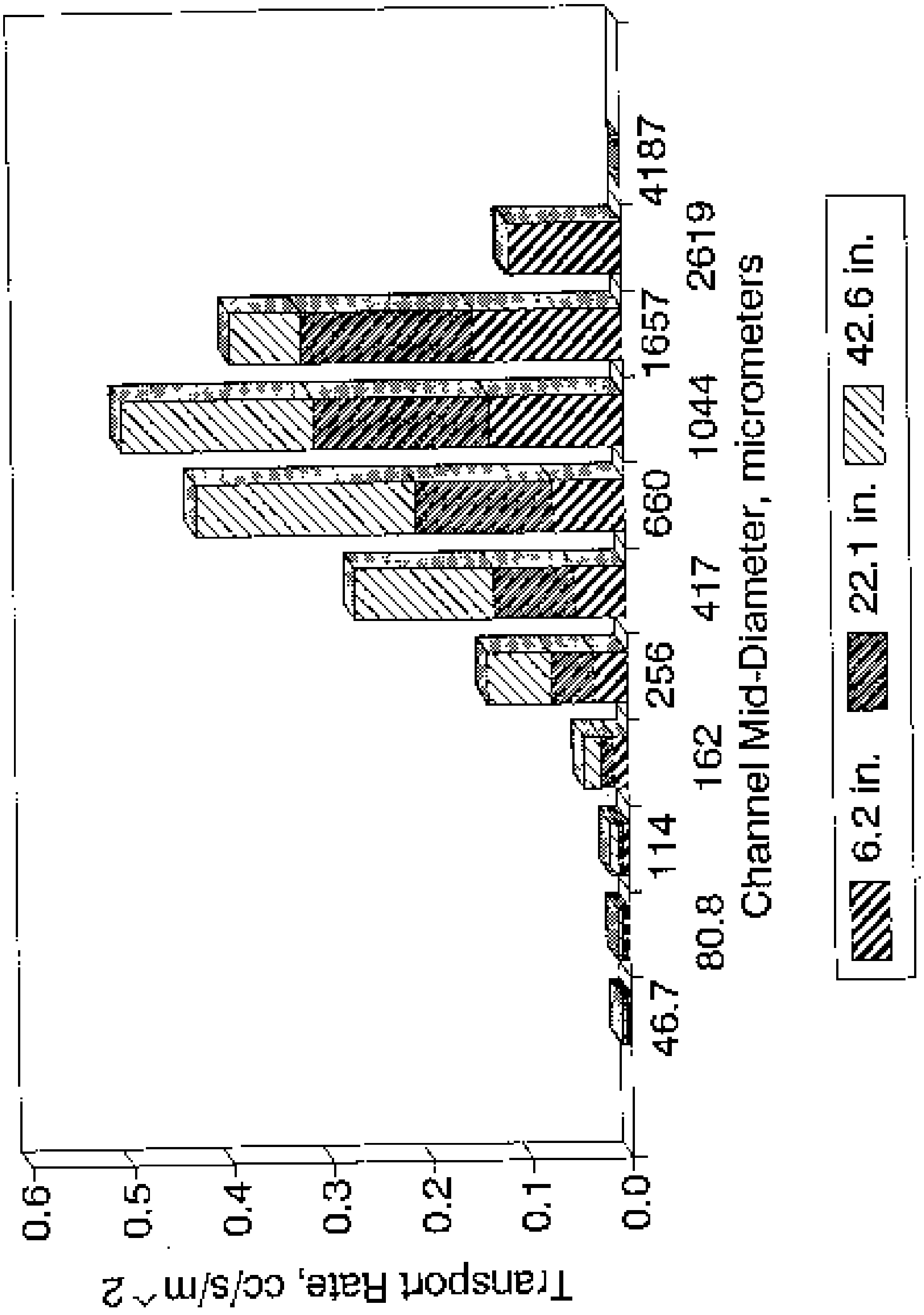


**FIGURE 4.9-12**

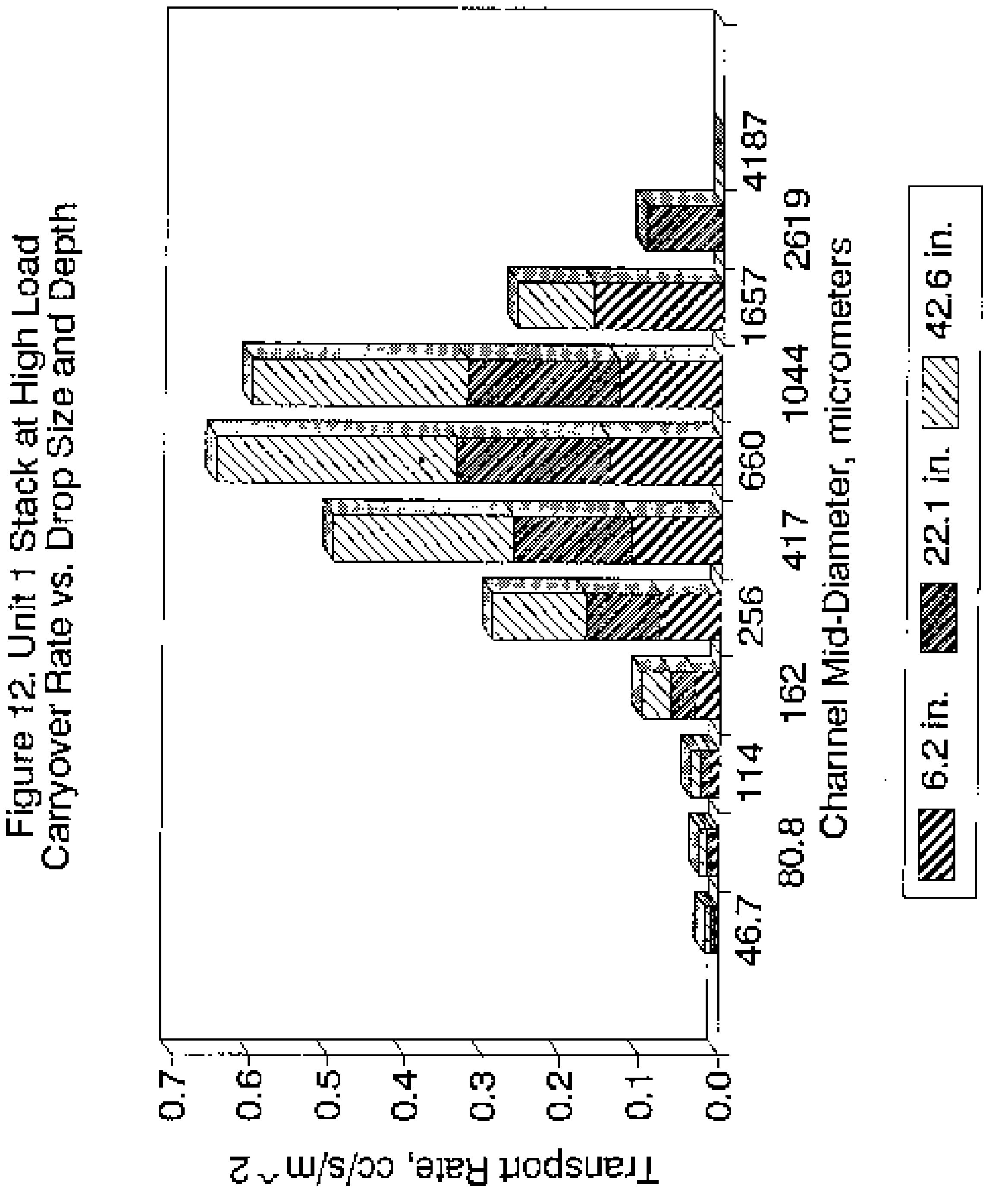


Figure 12. Unit 1 Stack at High Load
Carryover Rate vs. Drop Size and Depth
Transport Rate, cc/s/m^2
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
46.7
80.8
114
162
256
417
660
1044
1657
2619
4187
Channel Mid-Diameter, micrometers
6.2 in.
22.1 in.
42.6 in.

**FIGURE 4.9-13**

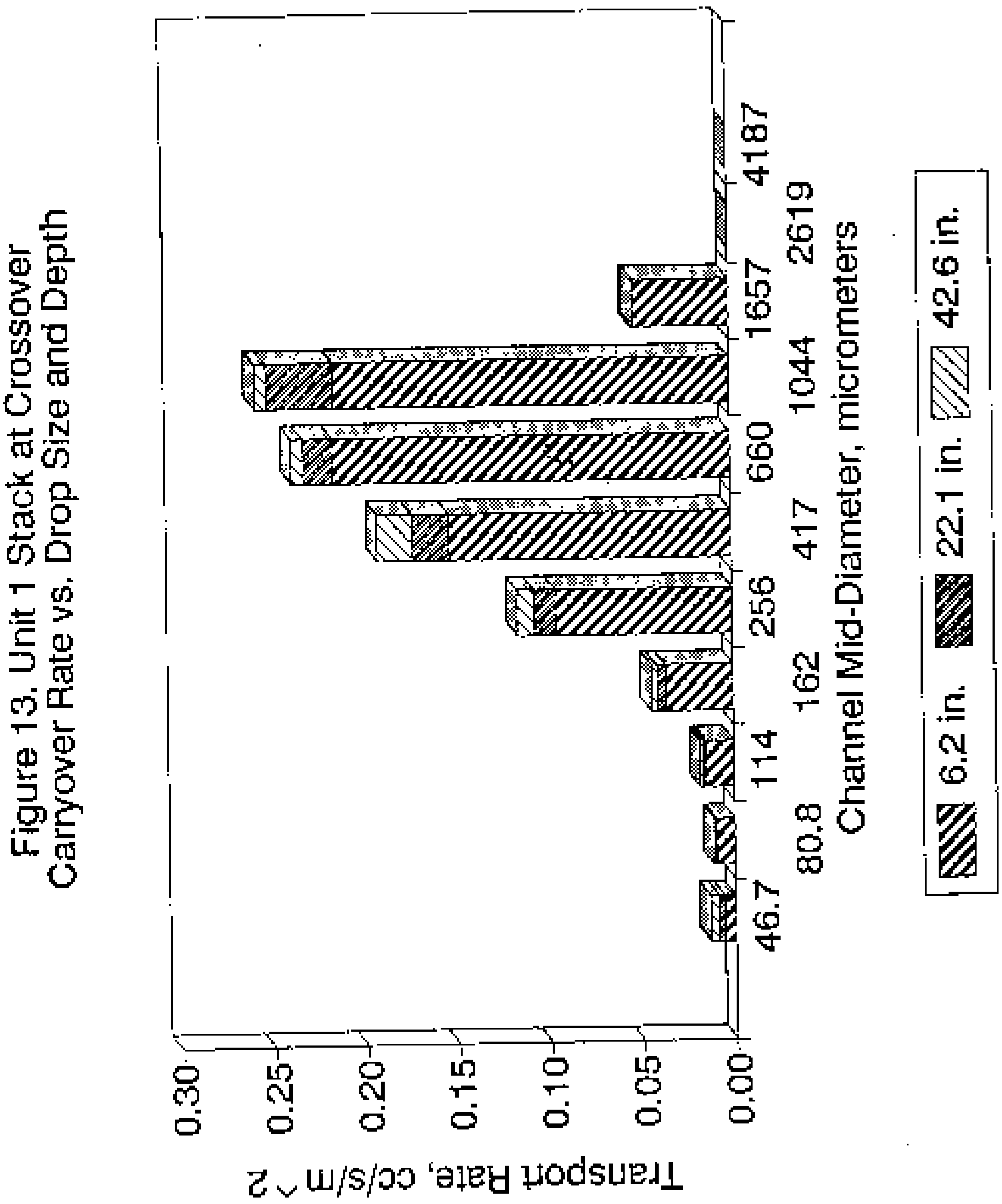


Figure 13. Unit 1 Stack at Crossover Carryover Rate vs. Drop Size and Depth

## FIGURE 4.9-14

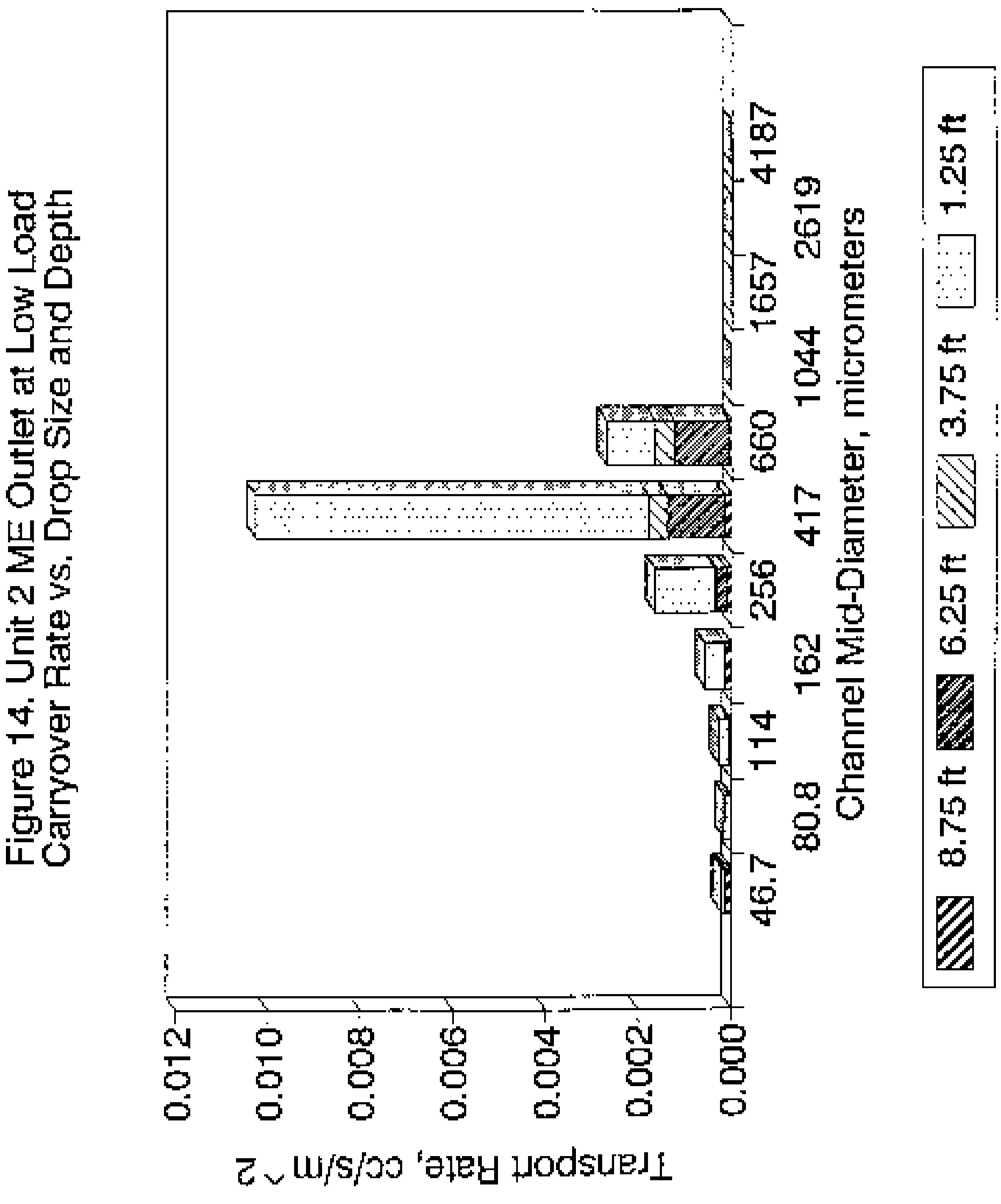


Figure 14. Unit 2 ME Outlet at Low Load Carryover Rate vs. Drop Size and Depth

**FIGURE 4.9-15**

Figure 15. Unit 2 ME Out at High Load Carryover Rate vs. Drop Size and Depth

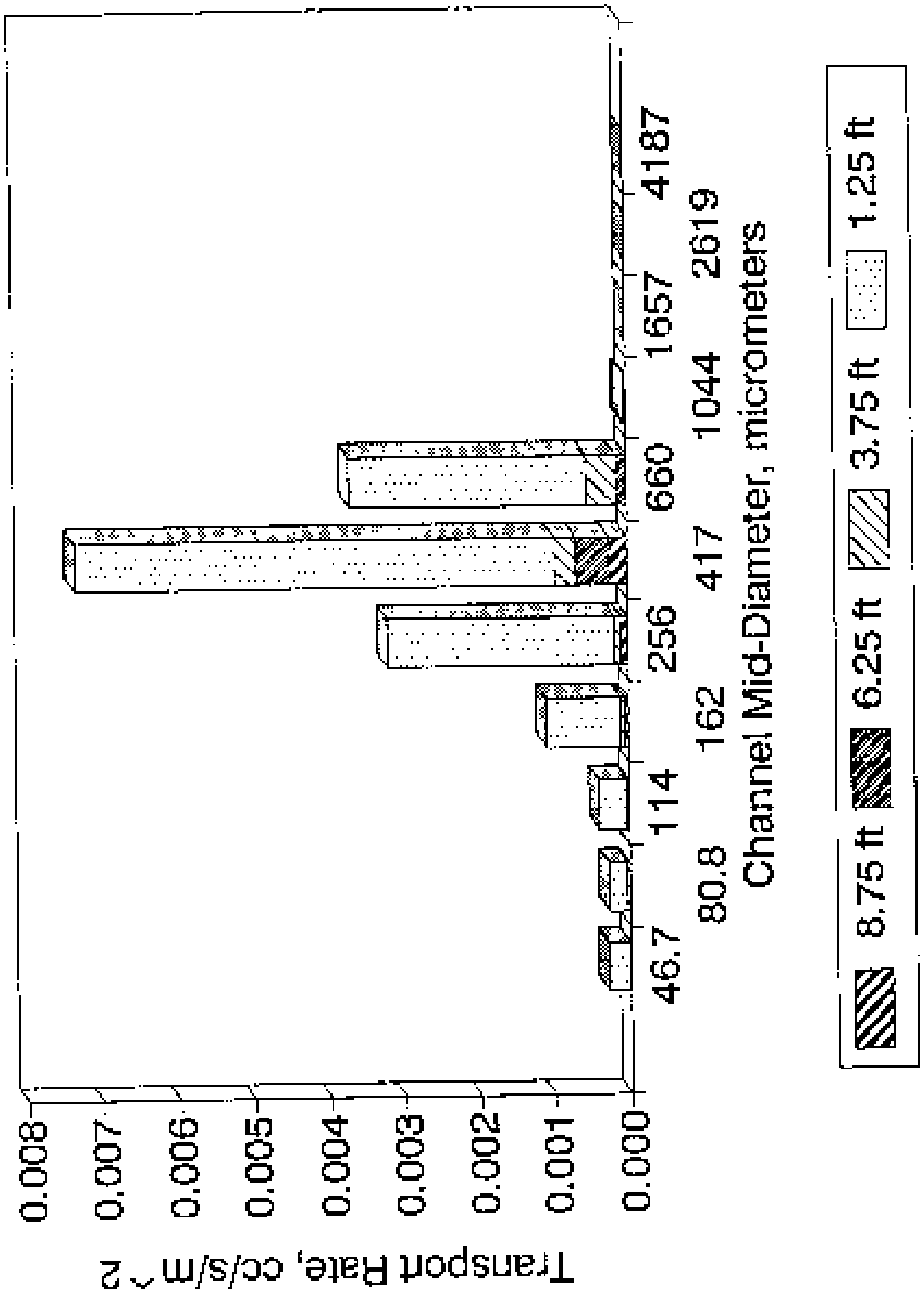


**FIGURE 4.9-16**

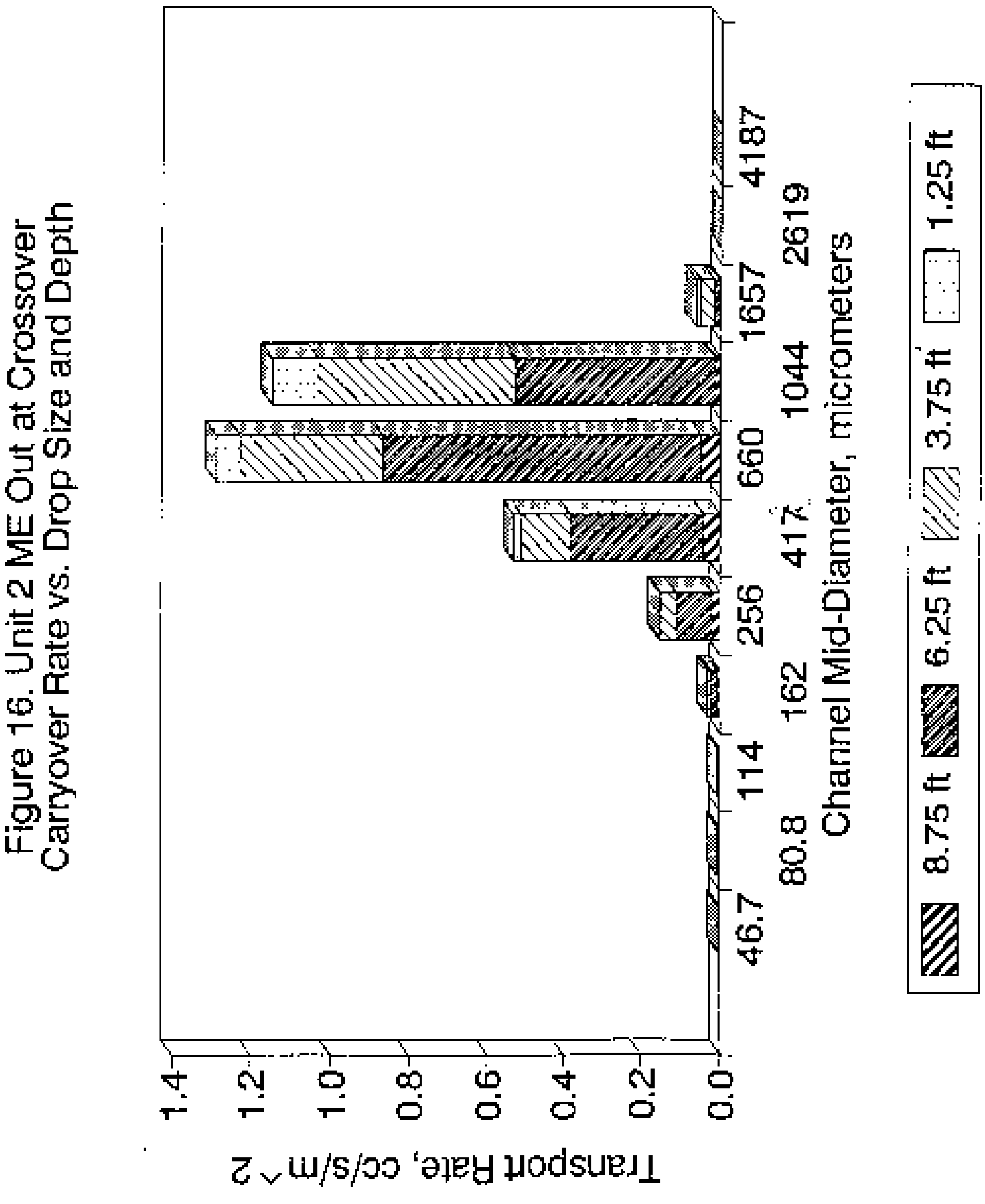


Figure 16. Unit 2 ME Out at Crossover Carryover Rate vs. Drop Size and Depth

**FIGURE 4.9-17**

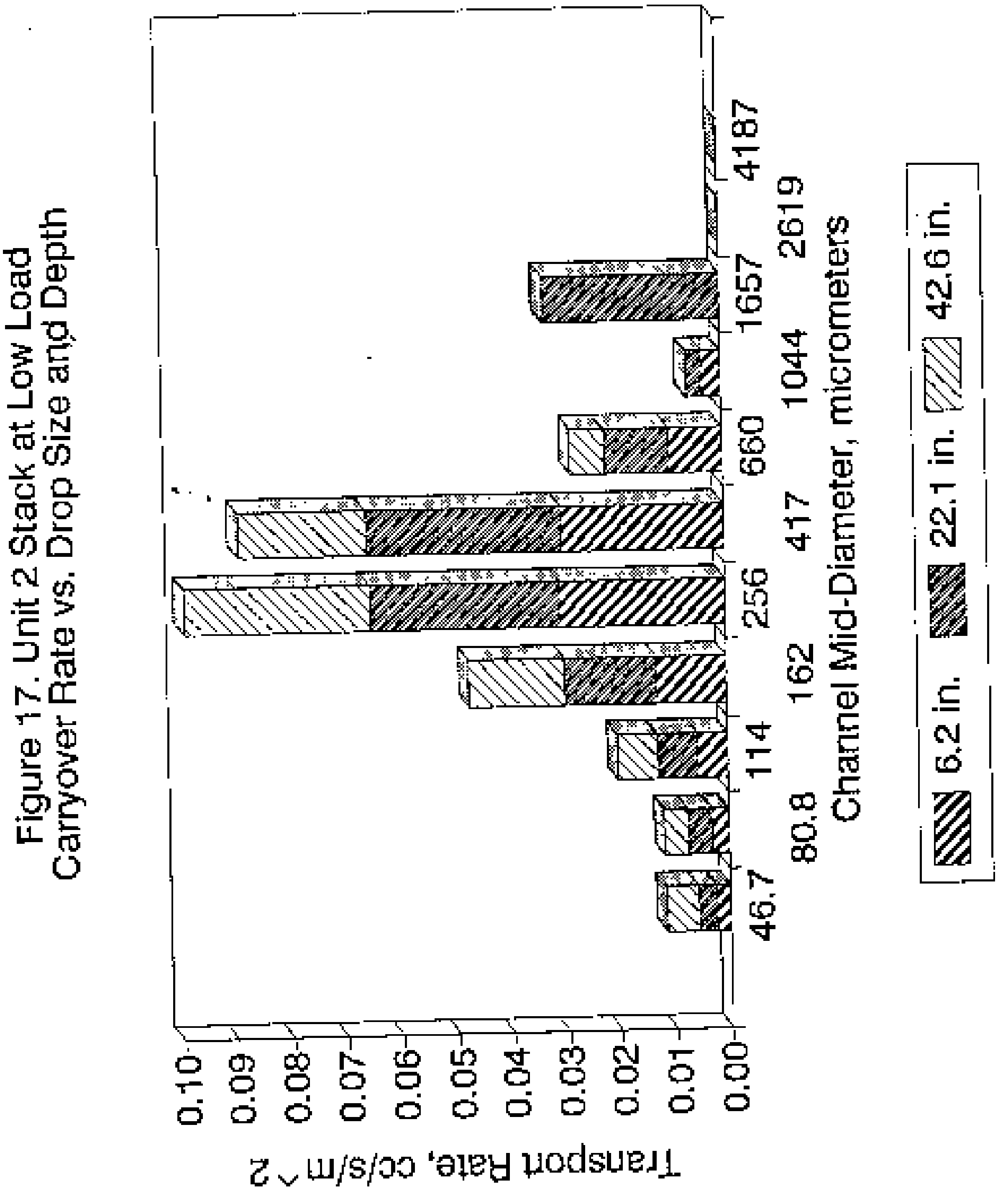


Figure 17. Unit 2 Stack at Low Load Carryover Rate vs. Drop Size and Depth

**FIGURE 4.9-18**

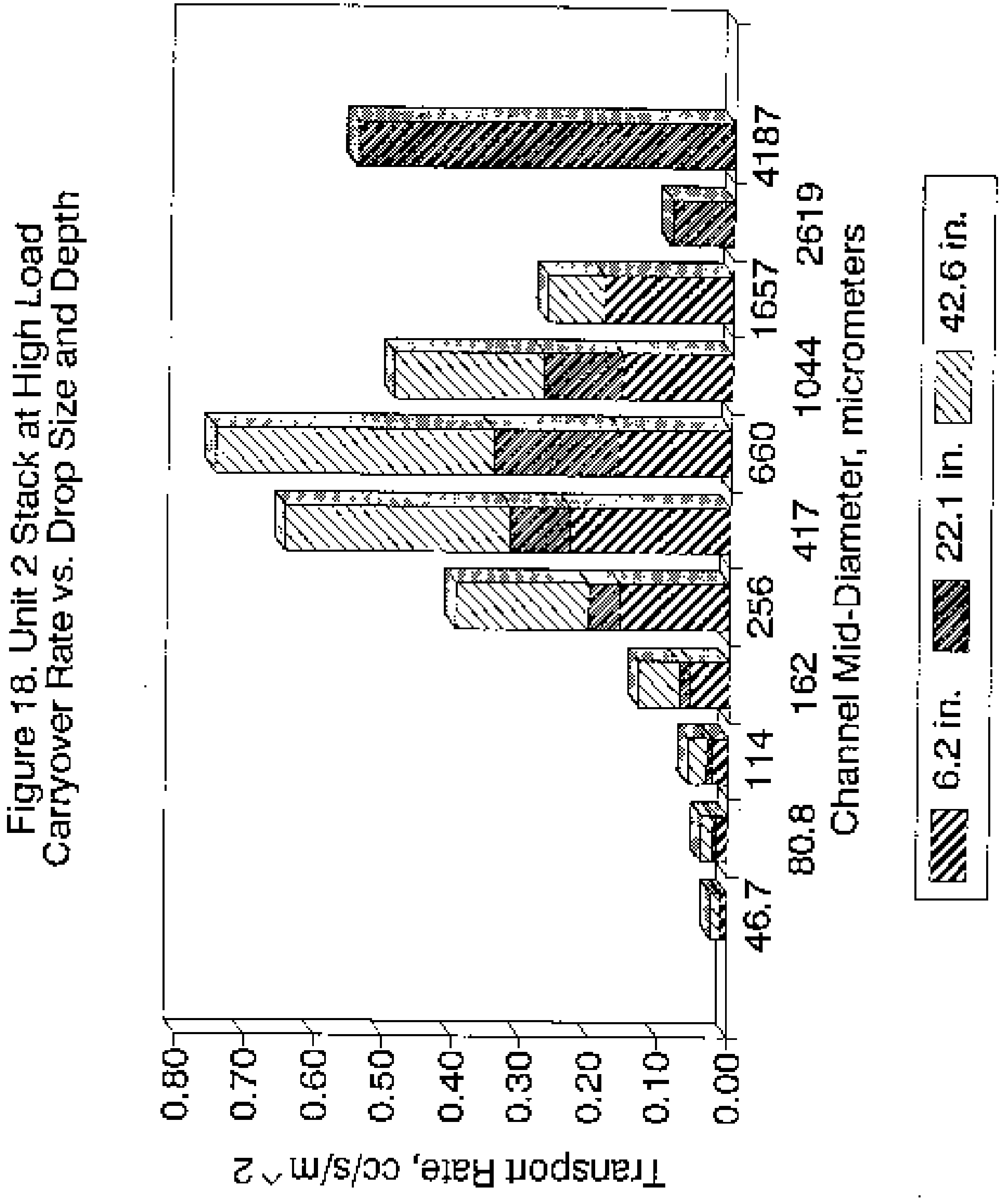


Figure 18. Unit 2 Stack at High Load Carryover Rate vs. Drop Size and Depth

## FIGURE 4.9-19

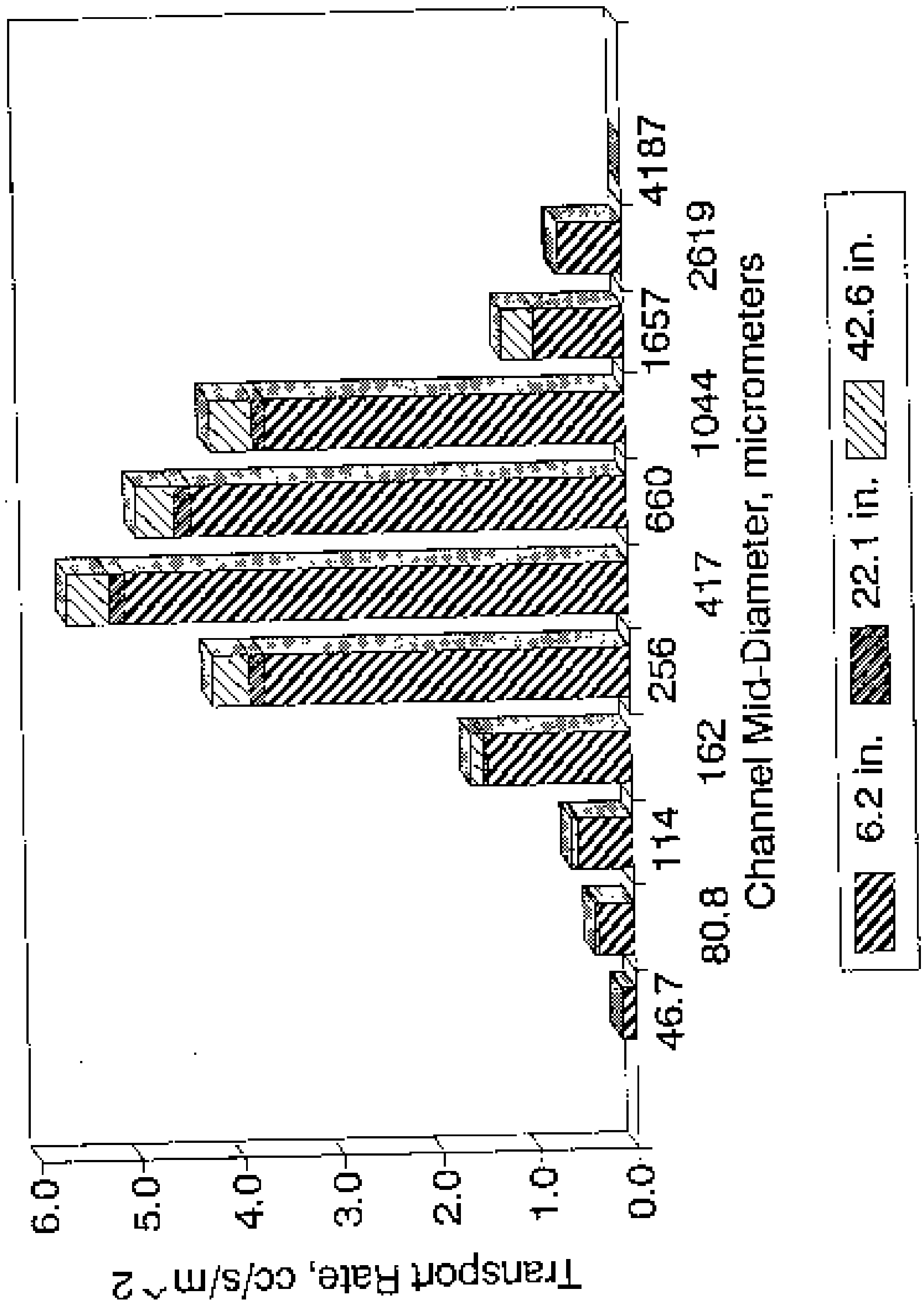


Figure 19. Unit 2 Stack at Crossover Carryover Rate vs. Drop Size and Depth

**FIGURE 4.9-20**

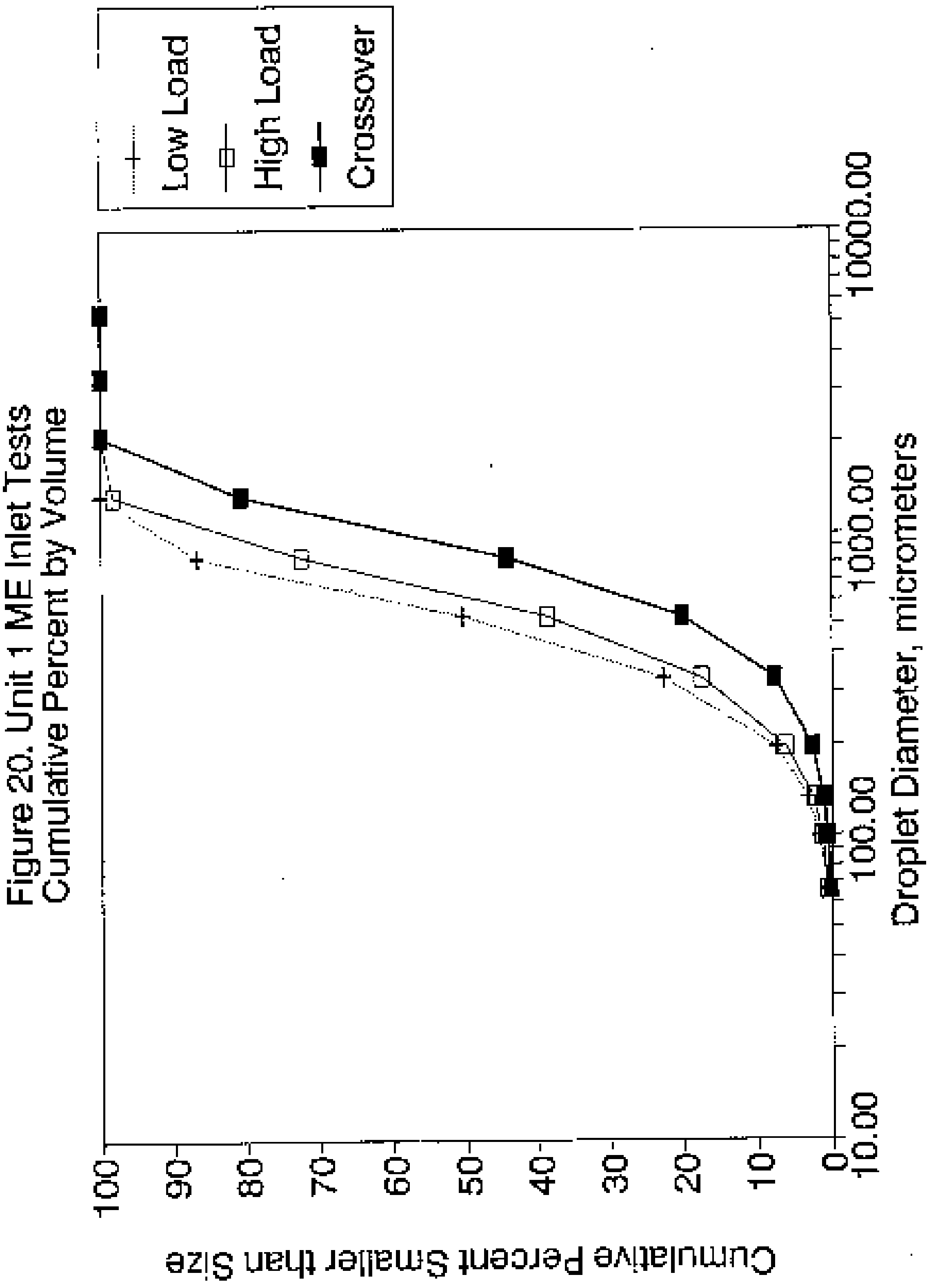


Figure 20. Unit 1 ME Inlet Tests
Cumulative Percent by Volume
Low Load
High Load
Crossover
Cumulative Percent Smaller than Size
100
90
80
70
60
50
40
30
20
10
0
10.00
100.00
1000.00
10000.00
Droplet Diameter, micrometers

**FIGURE 4.9-21**

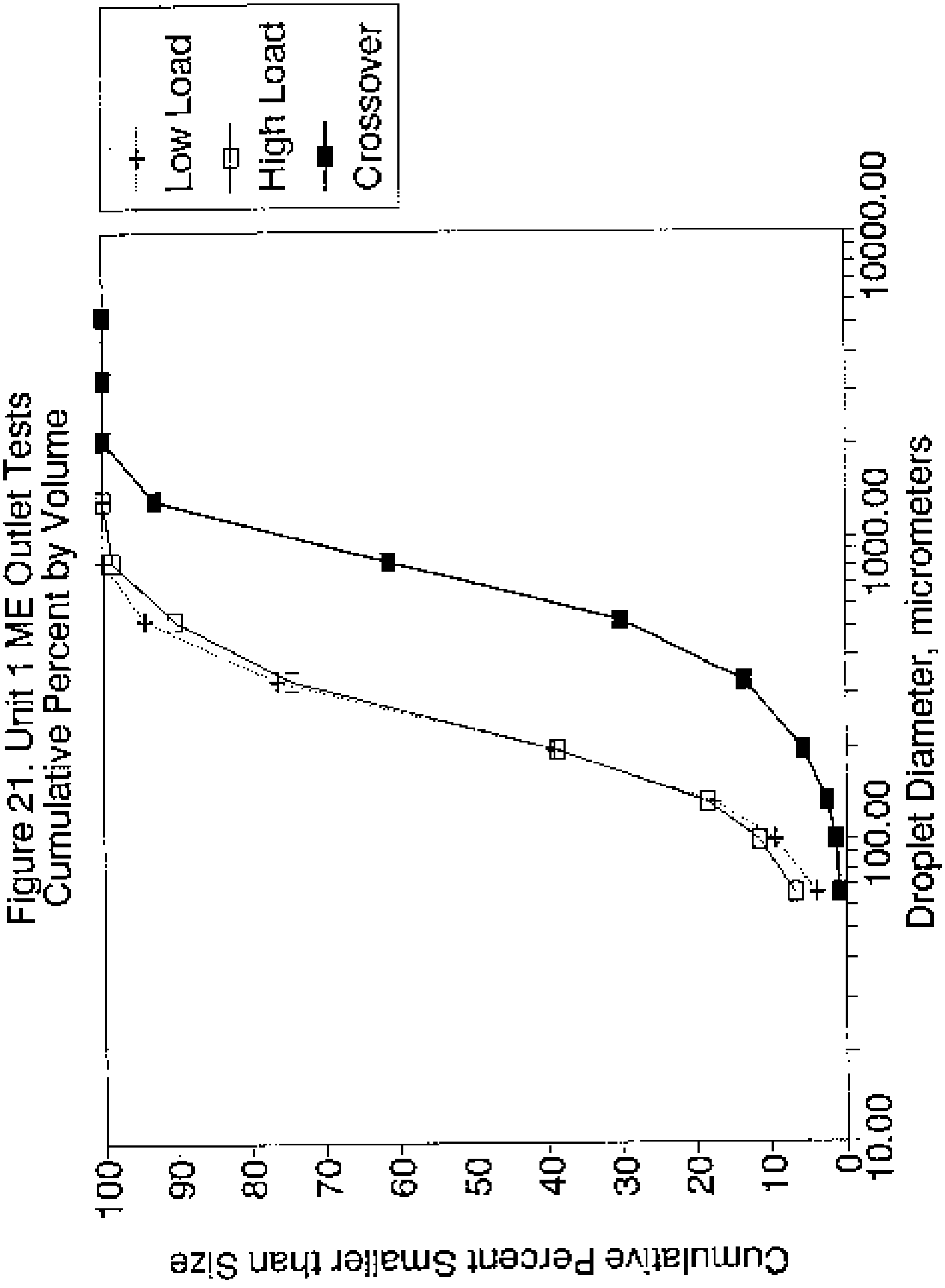


Figure 21. Unit 1 ME Outlet Tests
Cumulative Percent by Volume
Low Load
High Load
Crossover
Cumulative Percent Smaller than Size
100
90
80
70
60
50
40
30
20
10
0
10.00
100.00
1000.00
10000.00
Droplet Diameter, micrometers

**FIGURE 4.9-22**

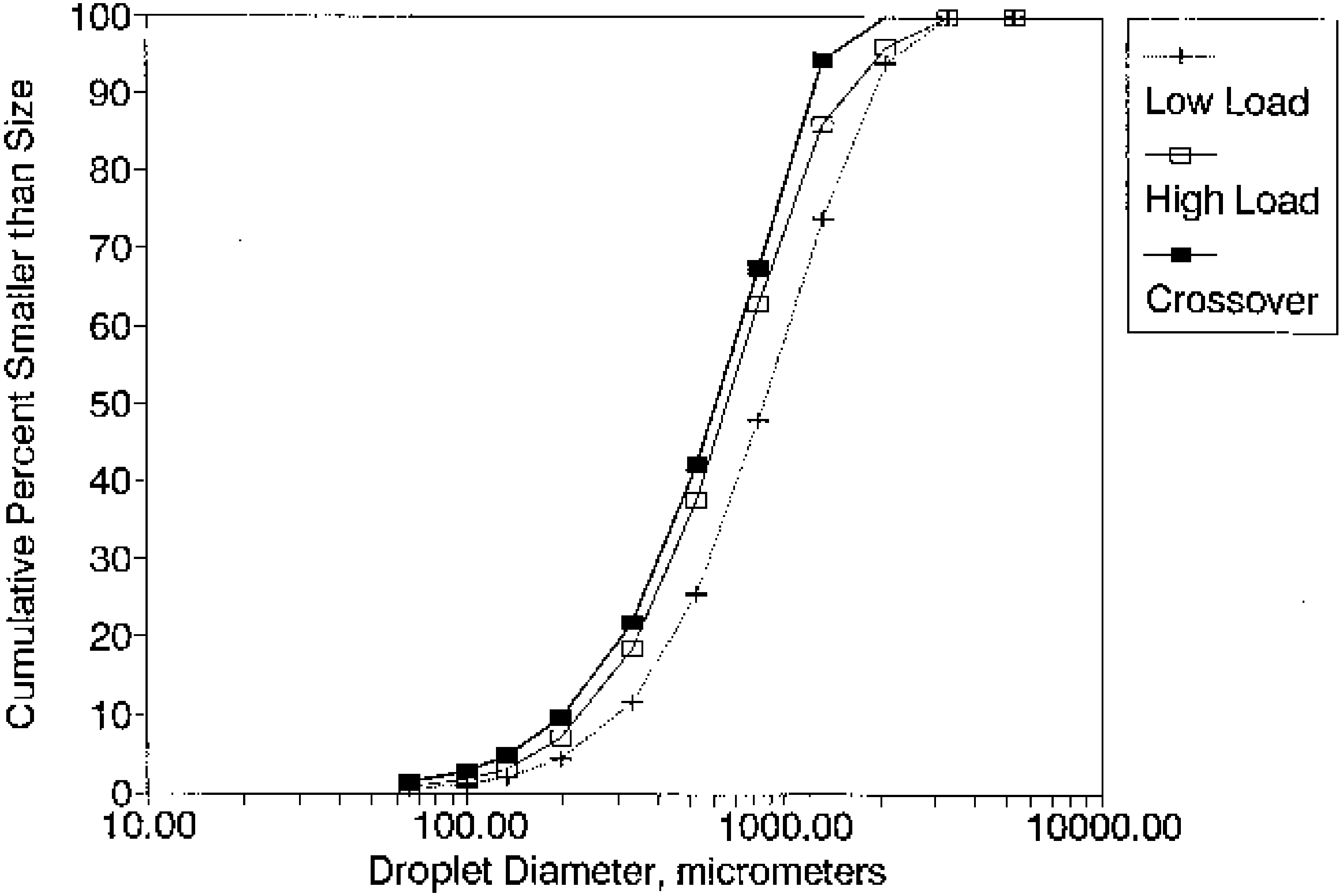


Figure 22. Unit 1 Stack Tests
Cumulative Percent by Volume

**FIGURE 4.9-23**

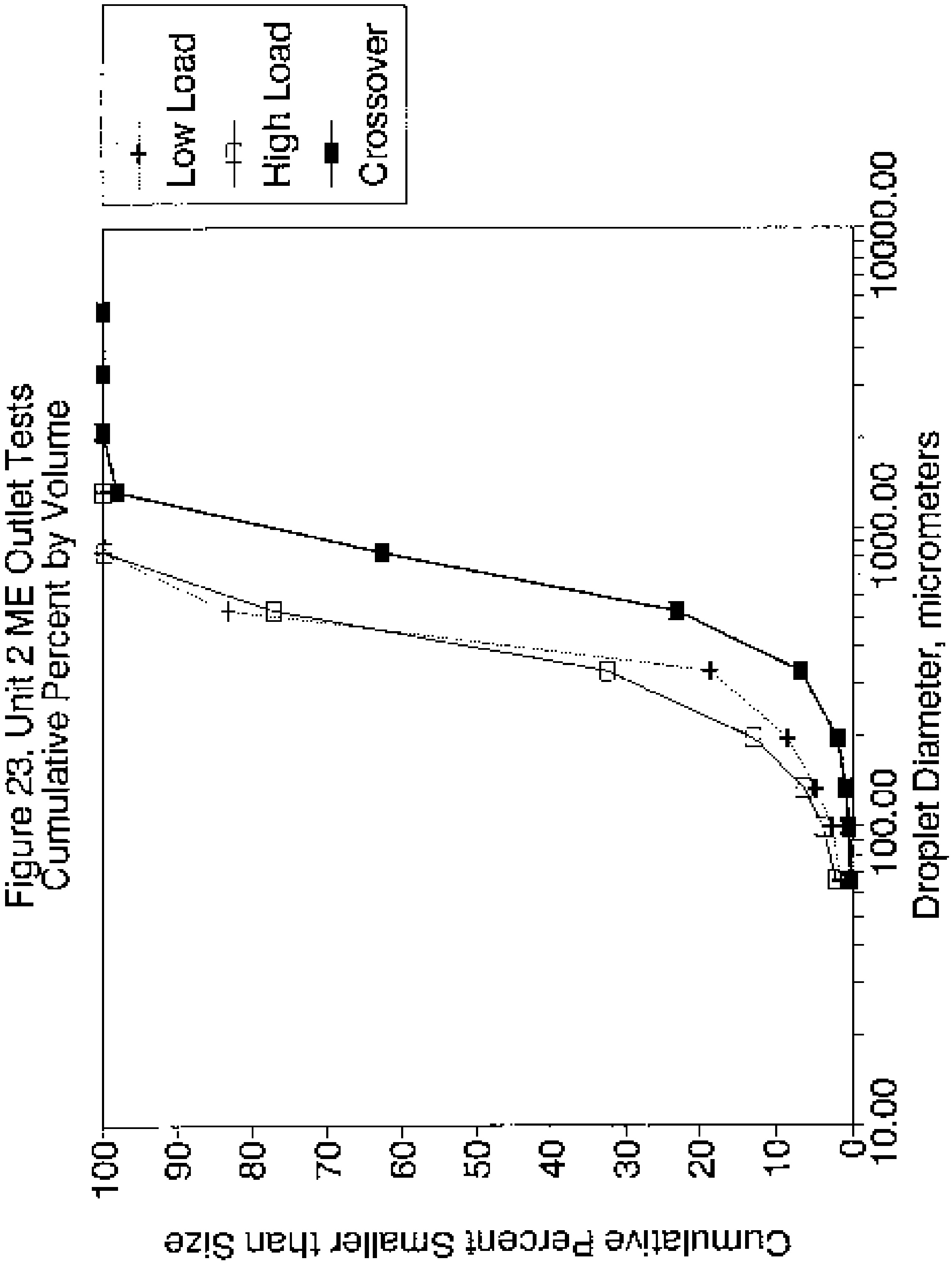


Figure 23. Unit 2 ME Outlet Tests
Cumulative Percent by Volume
Low Load
High Load
Crossover
Cumulative Percent Smaller than Size
100
90
80
70
60
50
40
30
20
10
0
10.00
100.00
1000.00
10000.00
Droplet Diameter, micrometers

**FIGURE 4.9-24**

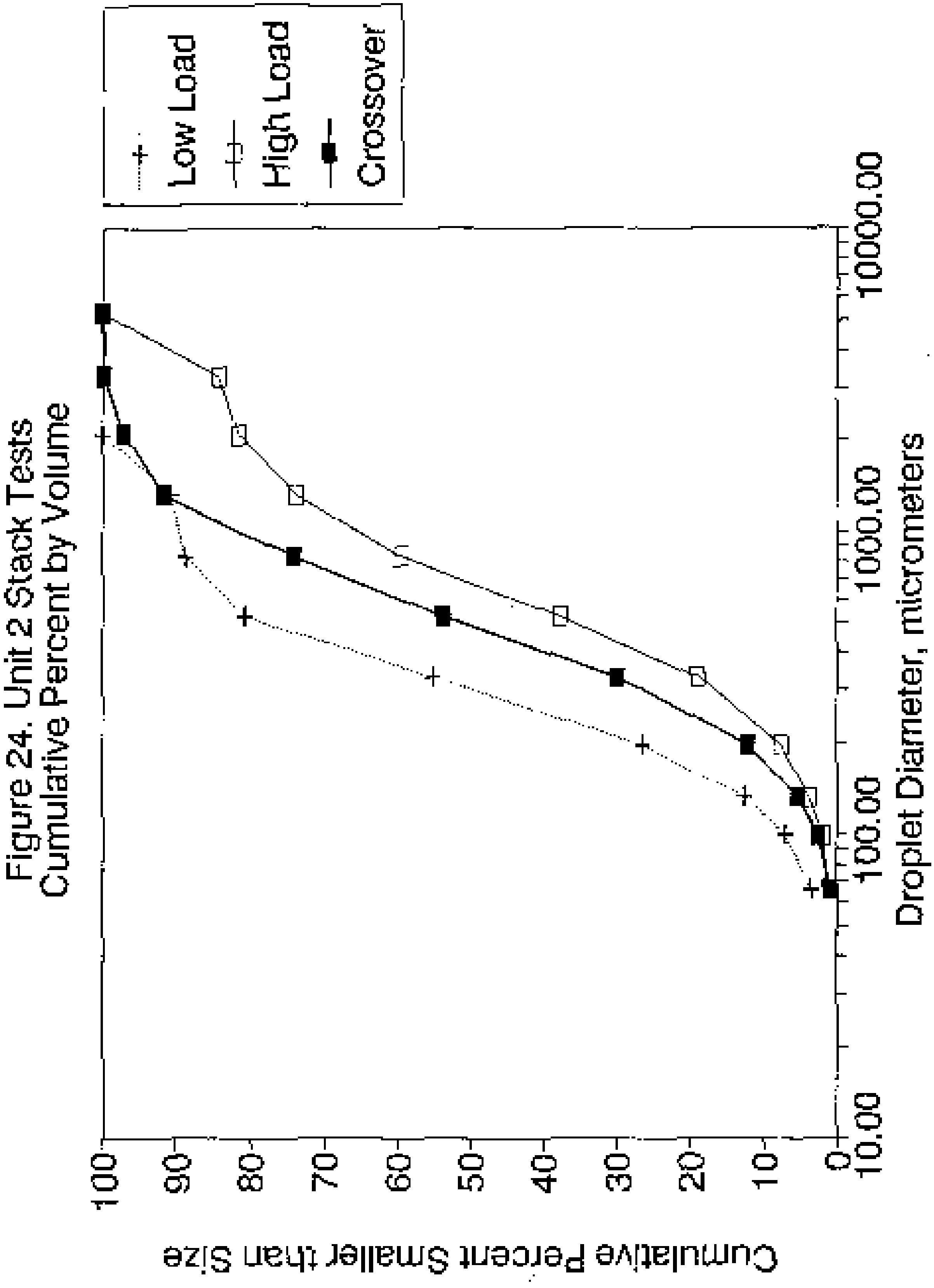


Figure 24. Unit 2 Stack Tests
Cumulative Percent by Volume
Low Load
High Load
Crossover
Cumulative Percent Smaller than Size
0
10
20
30
40
50
60
70
80
90
100
10.00
100.00
1000.00
10000.00
Droplet Diameter, micrometers

## 4.10 STEBBINS TILE TEST FACILITY

The purpose of the Stebbins Tile Test Facility was to document the techniques employed in constructing an absorber module, evaluate crack repair, mortar and tile wear, pipe penetrations and monitor operating and maintenance costs. A video was produced to document construction techniques for installation of scrubber walls. Evaluation indicated 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.

### 4.10.1 DESCRIPTION OF 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 test facility was completed on September 13, 1994 at the. 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 $SO_2$ 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.

### 4.10.2 INTERIM OBSERVATIONS

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.

### 4.10.3 INSPECTION AND DEMOLITION OF STEBBINS TILE TEST MODULE

During the week of December 8, 1997, the Stebbins Tile Test Module at the NYSEG Kintigh Station was inspected and demolished. The results of the inspection are documented in a report entitled “Inspection and Demolition of Stebbins Tile Test Module”, authored by CONSOL and dated February 1998. The complete report can be obtained by contacting DOE. A summary of the report is provided below.

#### INTRODUCTION

Inspection of the Stebbins Tile Test Module included:

- Photographs of the tile-lined interior of the module were taken.
- Grout joint profile depth measurements were made around the "Refrax” plugs on the north and south walls.
- Six 4-inch diameter cores were removed from the north, south and west walls.
- Steel reinforcement bars were inspected as the concrete walls and base were demolished with a jackhammer.
- The six cores from the walls and corroded steel reinforcement bars collected from the concrete base were photographed.
- 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.
- 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. No external leakage was ever observed at the foundation slab along the east and south walls where corroded dowels were found.

## INSPECTION AND EXAMINATION RESULTS

### History

A brief history of the Stebbins Tile Test Module is listed in Table 4.10-1.

### SEMPLATE® Tile Interior

Appendix 1.0 of the report contains overall photographs of the four walls, photographs showing the condition of the grout between a split tile on the south wall, and photographs of the "Refrax" plugs on the north and south walls. Figures 1.1 and 1.2 of the report show the results of joint profile depth measurements at the "Refrax" plugs. The maximum depth measured was 0.104" and minimum of 0.00" indicating a very little or no loss of grout in the joints.

### Core Sample Examination

Appendix 2.0 of the report contains a listing of the six 4-inch diameter core samples showing location and tile condition, and photographs of each core sample and the core hole. The examination of the cores was visual. Detailed testing of the cores may be done at a later date. The visual examination of core samples revealed the presence of shrinkage or thermal cracks which did not cause the interior tile face to leak.

### Steel Reinforcement Bars

The steel reinforcement bars in the walls were in good condition and no corrosion was found in areas deliberately allowed to leak. Appendix 3.0 of the report contains photographs of corroded reinforcement bars removed from the concrete foundation slab of the test module that were found at the bottom of the east and south walls. The reinforcement bars were used as dowels to connect the walls to the concrete foundation slab and extended from the concrete in the slab to the concrete in the wall. Based on an examination during demolition, the location of the corrosion on the dowels was at the parting line between the concrete in the slab and the wall, which were poured at different times. 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.

Figure 3.2 in the report shows the actual location of the dowels based on photos taken during construction and observations during demolition. 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.

### TABLE 4.10-1
### STEBBINS TILE TEST MODULE HISTORY

| Date | Total Elapsed Time-Hr. | Pump Operating Time- Hr. |
|---|---|---|
| 9-17-94[1] | 0 | 0 |
| 12-15-94[2] | 2,136 | 2,101.5 |
| 5-16-95[3] | 5,784 | 5,509 |
| 10-5-95[4] | 9,192 | 7,986 |
| 1-17-96 | 11,688 | 9,572 |
| 7-23-96 | 16,176 | 10,295 |
| 2-20-97 | 21,264 | 13,724 |
| 6-2-97 | 23,712 | 13,724 |
| 12-5-97[5] | 28,176 | 16,239 |

1. Leakage occurred in latency concrete area of south wall, but later stopped.
2. Holes were drilled in latency concrete area of south wall to reestablish leakage.
3. Holes in latency concrete area of south wall were filled with 3M Scotch seal chemical grout

No. 5600 foam.

4. Three cracked tiles were removed from the east wall and replaced.
5. 1 year = 8,760 hours, 3 years = 26,280 hours.

## 4.11 MILLIKEN HEAT PIPE AIR HEATER EVALUATION

The Milliken Heat Pipe Air Heater Evaluation program provided an independent evaluation of heat pipe air heater system for the US utility industry. The scope of the study included evaluation of thermal performance for the as-new condition and thermal performance degradation as a result of fouling and after cleaning. Corrosion of the heater and of coupons of alternate tube materials were also studied. The economic benefits of the system were reviewed including the effects of reduced air in-leakage, lower flue gas temperature, reduced washing requirements, smaller cold side primary air fan requirements, etc. The results of the evaluation program are presented in a report prepared by CONSOL. Inc. entitled: Heat Pipe Performance - Final Report (The Heat Pipe Final Report). What follows is a summary of that report. The full report can be obtained from DOE.

### 4.11.1 INTRODUCTION

As part of the CCT-4 program for Milliken Station, NYSEG replaced the two Ljungstrom® air preheaters on Unit 2 with two heat pipe air preheaters. This is the first time in the US that heat pipes have been used for both primary and secondary air preheating in a utility boiler. Potential benefits of using heat pipes for this service are:

- Reduction of induced draft (ID) fan power requirements by eliminating air heater air-in leakage;
- Reduction in downstream environmental control equipment size requirements for particulate removal and for the flue gas desulfurization contactor due to reduction in flue gas flow;
- Reduction of power requirements for the primary and secondary air fans by eliminating seal air leaks in air heater;
- Improved thermal performance of the boiler because the air heater operates at lower flue gas exit temperatures;
- Better control of corrosion in the air heater due to more stable cold end operation.

The purpose of the Heat Pipe Air Heater Evaluation program was to evaluate the effects of operating conditions on heat transfer rate, air in-leakage and corrosion rate. In addition the program was to characterize the operation of the heat pipe, quantify its benefits, and establish guidelines for purchase or use by other utilities.

### 4.11.2 HEAT PIPE DESCRIPTION

Figure 4.11-1 shows the process flows for the heat pipe air preheaters installed at the Milliken Station Unit 2 boiler. The two parallel heat pipe air preheaters are located between the boiler economizer and the electrostatic precipitator. Hot flue gas from the economizer is used to heat both the primary and secondary air streams. The flue gases enter the exchanger at 680 °F (design) and exit at about 253 °F (design). Two ducts from the boiler supply hot flue gases to the heat pipe air heaters, one duct to each air heater. The flue gases approach the air heaters through horizontal ducts. A set of ladder vanes inside the ductwork hood mounted on top of each heat pipe redirects the flue gas flow vertically downward to the heat pipe tube banks. The tube banks are split into one primary and two secondary flue gas sections. A non-pressure bearing baffle is used to separate the areas for primary and secondary air heating. Gas distributes to the sections based on the pressure drop through the sections. When the air heaters were originally installed, the primary flue gas sections did not have inlet dampers. Louvered dampers were later installed by NYSEG to provide better temperature control and reduce the potential of overheating the hottest toluene filled tubes. Closing the dampers reduces the flow through the primary flue gas section and increases the flow through the secondary flue gas sections. However, primary flue gas flow adjustments have little effect on the overall secondary section flows since the primary gas flow is normally only about one-eighth the secondary flow. Flue gas and air temperatures to and from the heat pipes are monitored using multi-point thermocouple grids, which conform to ASME Power Test Code, PTC, requirements for gas temperature measurements.

As shown in figure 4.11-1, each heat pipe exchanger is designed to heat both primary and secondary air streams in separate sections. This design provides added flexibility for coal drying and in achieving maximum heat recovery. Separate primary air fans supply air to the preheaters. Air leaving the primary air preheat section is at 650 °F (design). The heated air is directed to the coal mills where it is used to dry the coal during pulverization and convey the coal to the boiler burners. A separate forced draft (FD) fan supplies secondary air to each air preheater. The air enters the preheater at 80 °F and exits at about 617 °F (design). The heated air then flows to the boiler burners. Bypasses are provided for both the primary and secondary air streams. The primary air bypass is external to the heat pipe and is used to supply tempering air at the coal mills. The secondary air bypass is internal and an integral part of the heat pipe. An electrically driven damper inside the heat pipe is used to control the flow through the secondary air bypass. This bypass is used primarily to limit heat transfer from the flue gas section to avoid low cold-end tube temperatures which result in acid condensation. Under certain conditions, bypass control must be limited to prevent overheating of the hottest operating toluene filled tubes. In each air preheater, the primary air and secondary air sections are separated by pressure bearing walls.

## 4.11.3 PERFORMANCE TESTING

### TEST PROCEDURE DEVELOPMENT

After a new piece of equipment is installed, the purchaser often wants to know, first, if the equipment meets design performance and then, how well does the equipment perform after being in service for an extended period? To answer these questions for the Milliken Station heat pipe air heaters, the thermal performance was measured under (1) clean unfouled conditions, (2) fouled conditions after six months of operation, and (3) cleaned condition following a water washing to establish any performance decline. A detailed equipment test procedure specifically for the Milliken heat pipe air heater arrangement was developed. The detailed procedure is based on the American Society of Mechanical Engineers (ASME) Performance Test Code for Air Heaters. It specifies how the air heaters will be operated, what data (temperature, pressure, composition, flow rate, etc.) will be obtained, how the data will be obtained, and how the data will be used in certain calculations. The equipment test procedure was followed each time the heat pipes were tested. The full text of the procedure can be found in Appendix D of the Heat Pipe Final Report.

Because of the importance of air heaters to the operation of fossil fuel fired utility boilers, the ASME developed a general procedure, PTC 4.3, for establishing equipment performance. Rarely is it possible to determine equipment performance by establishing design inlet conditions to compare directly the measured flue gas outlet temperature with the design value. Fuel feedstocks may change, so flue gas composition will be different than design; ambient air temperatures change with the time of year and even the time of day; and flue gas temperatures to the air heaters will depend on boiler conditions such as cleanliness, excess air, load, steam attemperation rates, etc. The ASME code procedure avoids this problem by not requiring that design inlet conditions be established. Rather, performance data are collected under some stable operating condition (usually at high boiler load) and then corrections are applied to adjust the flue gas outlet temperature back to design conditions.

The code requires that corrections be applied for differences from design inlet air temperature, design inlet flue gas temperature, design inlet flue gas rate, and design X-ratio. The corrections are based on a simplification of the heat transfer process physics. For example, corrections for differences from design inlet air and inlet flue gas temperatures are derived based on the assumption of constant gas side efficiency (effectiveness). Applying the correction factors results in a “totally” corrected flue gas outlet temperature. Performance is determined by comparing this temperature with the design flue gas outlet temperature. If the totally corrected temperature equals the design flue gas outlet temperature, the performance exactly matches design; a higher temperature indicates a poorer than design performance; and a lower temperature indicates a better than design performance.

The ASME test code specifies how the first two corrections (for differences from design inlet air and flue gas temperature) are to be calculated but does not specify exactly how to calculate corrections for flue gas flow and X-ratio. A method for calculating these corrections is presented in the uncertainty analysis report for the totally corrected flue gas outlet temperature in Appendix E of the Heat Pipe Final Report.

In addition to providing a method for comparing the measured thermal performance with design, the ASME test code also specifies procedures for comparing air leakage and air and flue gas side pressure drops with design values. Since the ASME Test Code specifies what data are to be collected and how most of the calculations are to be done, use of the code helps to reduce disputes between the supplier and the end user concerning the actual performance.

## TEST PORT REQUIREMENTS

Determining the average temperatures and compositions of all streams around the air heaters is critically important in assessing the thermal performance of the units. Multi-port probe traverses are generally used to obtain temperature/flow data in the large ductwork around full-scale air heaters. Because of potential flow stratification, simple averaging of the temperature and composition data may lead to inaccurate performance calculations. To avoid this, the ASME code procedures recommend that flow weighted average temperatures and/or gas compositions generally be obtained. This was done for all performance tests.

For the Milliken test program, the ASME recommendations on test port layout were followed i.e., for rectangular ducts, ports were no more than three feet apart and at least four ports were installed on each duct. For round ducts, two ports were installed at 90 degree separation. NYSEG, ABB/API, and CONSOL R&D worked together to identify sampling port needs and locations. Each heat pipe required 40 sampling ports and 20 special taps for code performance measurements. In addition to these ports and taps, 26 taps were required on each heat pipe for diagnostic purposes. The ports and taps are listed in table 4.11-1.

Installing the ports and taps was costly since most were added to the ductwork or heat pipe in the field. Costs can be reduced if the required number and locations of ports and taps can be identified during the design phase to take advantage of shop fabrication.

Provisions also had to be made for personnel access to the sampling ports. The most difficult location was the flue gas outlet duct ports on the west side of the heat pipes. Access to this area required approximately 135 feet of supported catwalk, railings, and three metal ladders. The additional structure made sampling convenient and safe and was justified based on safety concerns alone, since the ports were approximately 40 feet above the ground floor.

## PERFORMANCE GUARANTEES

The main reason for replacing the Unit 2 Ljungstrom® air heaters with heat pipes was to decrease the plant heat rate sufficiently to off set most of the incremental power consumption due to the installation of the FGD system. The heat pipe design offered the potential of achieving this by operating with lower flue gas outlet temperatures to recover more heat and by reducing fan (PA, FD, ID) and FGD pump power requirements through elimination of air leakage. The specific guarantees for the combined two heat pipe system were to reduce the temperature of 1,500,000 lb/hr of flue gas from an entering temperature of 680$^0$F to 253$^0$F using 125,000 lb/hr of primary air entering at 80$^0$F and 1,125,000 lb/hr of secondary air entering at 80$^0$F based on a flue gas side specific heat of 0.2597 Btu/lb-$^0$F and an air side specific heat of 0.2469 Btu/lb-$^0$F. The air side pressure loss was not to be more than 5.35 in. WC and the average flue gas side loss was not to exceed 3.65 in. WC. The unit is guaranteed for zero air to gas leakage. Additionally, the unit is guaranteed to operate for six months without a water wash while a 3.2% sulfur coal is fired. System cleanliness is expected to be maintained using a maximum of four sootblowing cycles per day. The thermal performance, gas side pressure drop, and zero leakage guarantees extend to the end of the six-month period of acceptable operation.

## UNCERTAINTY ANALYSES

Measurement errors are a concern for all parties involved in equipment performance evaluations, particularly when determining if guarantees are being met. To determine what allowance should be given for such errors, ABB/API and NYSEG requested that CONSOL R&D calculate the overall uncertainties for:

- The weighted average inlet and outlet temperatures for the primary air, secondary air, and flue gas streams.
- The air and flue gas flow rates.
- The air-to-gas leakage.
- The totally corrected flue gas temperature leaving the air heater.

Two uncertainty analyses were performed. The first analysis covered the first 3 items while the second analysis covered the last item. Both analyses are presented in Appendix E of the Heat Pipe Final Report. Measurement errors fall into two categories, bias errors and random errors. The bias errors are fixed errors which remain constant during a test and cannot be reduced by repeated measurement of a parameter. An instrument off set would be an example. Random errors are errors which can be reduced by repeated measurement. Errors caused by signal noise or reading errors due to changes in personnel are examples. Both types of errors are propagated separately through the performance code calculation procedures to obtain an estimate of the individual uncertainties (bias or random) in the calculated result. These uncertainties are then combined using an appropriate statistic for the uncertainty interval of interest.

For a 95% confidence level, the uncertainty in the weighted temperatures was shown to be about ±1% of the measurement in Fahrenheit degrees. The uncertainty in the air and gas calculated flow rates ranged from 4.9% to 6.7% of the value. The air leak uncertainty was shown to be about 1.7% absolute. These uncertainties are all low and provide confidence in the calculated results. The bottom line in evaluating the thermal performance is, however, the uncertainty in the totally corrected flue gas outlet temperature for the combined primary and secondary flue gas sections.

The uncertainty in the ASTM code procedure for calculating this temperature was shown to be about $\pm 4.4^0$F. Therefore, for a $253^0$F performance target, a totally corrected flue gas outlet temperature of $257^0$F would still be in the expected uncertainty range and would indicate acceptable performance.

## TABLE 4.11-1

## SAMPLE PORT/TAP REQUIREMENTS FOR EACH HEAT PIPE

| Location | Duct Size, Width-Depth | Traverse Points | Port Size | Number |
|---|---|---|---|---|
| Primary Air Inlet (on HP) | 17.5'-3.28' | 12 | 2" | 6 |
| Primary Air Outlet Duct | 48" dia. | 20 | 2" | 2 @ $90^0$ |
| Secondary Air Outlet Duct | 6'-9' | 24 | 2" | 4 |
| Flue Gas Inlet Duct | 14.5'-5.5' | 20 | 4" | 5 |
| Flue Gas Outlet Duct | 34'-2.5' | 24 | 4" | 12 |
| Primary Flue Gas Out (on HP) | 17.92'-3.28' | 14 | 2" | 7 |
| Secondary Air Bypass (1) | 17.5'-2.09 | 8 | 2" | 4 |
| **Total** | | | | **40** |
| **Special TC Taps** | | | | |
| Secondary Air FD Fan Discharge | | 4 | 1/2" | 4 |
| **Pressure Taps on Heat Pipe (2)** | | | | |
| Primary Air Inlet | | | 3/8" | 2 |
| Primary Air Outlet | | | 3/8" | 2 |
| Secondary Air Inlet | | | 3/8" | 2 |
| Secondary Air Outlet | | | 3/8" | 2 |
| Primary Flue Gas Inlet | | | 3/8" | 2 |
| Primary Flue Gas Outlet | | | 3/8" | 2 |
| Secondary Flue Gas Inlet | | | 3/8" | 2 |
| Secondary Flue Gas outlet | | | 3/8" | 2 |
| **Total** | | | | 20 |
| Primary Flue Gas Damper DP | | | 3/8" | 2 |
| Flue Gas Tube Bank DPs (Front Wall) | | | 3/8" | 8 |
| Flue Gas Tube Bank DPs (Side Wall) | | | 3/8" | 16 |
| **Total** | | | | **26** |

(1) Code requirement of three foot maximum distance between ports not adhered to since ports were only used to check for zero flow in bypass duct.

(2) Pressure taps are two taps spaced one foot apart and Y'd together.

## THERMAL PERFORMANCE

For the Milliken CCT-IV test program, the ASME PTC 4.3 procedure was used to evaluate the thermal performance of the new heat pipe air heaters. This procedure is costly and time consuming to conduct properly, but it provides an ideal means of evaluating the air heaters to determine if guarantee performance is achieved and can be used to track performance loss due to mechanical failure or fouling. The procedure establishes the actual performance regardless of shifts in inlet conditions from the design basis. As explained above, this is done by calculating temperature corrections to the measured flue gas outlet temperature which refer back to the design conditions. If the recalculated, i.e., totally corrected, flue gas outlet temperature is equal to or less than the design outlet temperature, the performance matches or exceeds the design. Use of the code procedure is a more exact means of assessing performance than other techniques such as, comparing or following changes in total heat transferred, thermal effectiveness, log mean temperature difference, or UA (overall heat transfer coefficient x area).

Three detailed, high load performance tests were conducted. Detailed reports covering each test may be found in Appendix F of the Heat Pipe Final Report. The first test was a clean condition test conducted 41 days after a boiler start-up. The second test was a fouled condition test conducted just over six months (187 days) after a clean condition start-up. The third test was a clean condition test conducted 20 days after heat pipe washing. This last test was used to assess the thermal recovery following water washing of fouled units and to address guarantee performance since the cleaning prior to the test was considered acceptable by the manufacturer ABB/API. Test results are summarized in table 4.11-2. The table provides temperatures and flows for the main streams which pass through the heat pipes, the temperature correction terms and the corrected flue gas outlet temperatures from the primary and secondary sections, and the combined totally corrected flue gas outlet temperatures.

The clean condition tests were conducted to assess the guaranteed performance, so these tests were done in duplicate. However, for the first 2B heat pipe clean condition test (May 14, 1996), a problem with the inlet flue gas analysis was discovered after the data were collected. Although adjustments were made using an alternate calculation procedure, the result is not presented here. The fouled condition tests were conducted to establish the degree of performance decline after six months of operation. These tests were mainly of academic interest, so to save costs duplicate testing was not done.

## Table 4.11-2

### Heat Pipe Thermal Performance
### Totally Corrected Flue Gas Outlet Temperatures (1)

| | 2A | | | | | 2B | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Date** | 5/14/96 | 5/15/96 | 10/7/96 | 11/7/96 | 11/8/96 | 5/14/96 | 5/15/96 | 10/8/96 | 11/7/96 | 11/8/96 |
| **Test Condition** | **Clean** | | **Fouled** | **After Wash** | | **Clean** | | **Fouled** | **After Wash** | |
| **Boiler Load, MW net** | **149.0** | **147.2** | **142.4** | **146.9** | **147.8** | **(2)** | **147.2** | **142.2** | **146.8** | **147.8** |
| **Primary Section** | | | | | | | | | | |
| Primary Air Rate, lb/hr | 75,900 | 73,600 | 56,400 | 58,800 | 73,500 | | 73,500 | 59,300 | 53,600 | 68,700 |
| T In, °F | 111 | 116 | 120 | 115 | 106 | | 116 | 112 | 115 | 107 |
| T Out, °F | 593 | 605 | 600 | 604 | 576 | | 590 | 614 | 614 | 592 |
| Primary Flue Gas Rate, lb/hr | 98,070 | 105,700 | 85,300 | 92,980 | 97,000 | | 85,900 | 111,800 | 80,510 | 91,570 |
| T In, °F | 675 | 677 | 667 | 659 | 658 | | 671 | 655 | 663 | 661 |
| T Out, °F | 294 | 304 | 330 | 324 | 288 | | 269 | 368 | 325 | 283 |
| T Out No Leak, °F (3) | 323 | 356 | 368 | 368 | 322 | | 287 | 404 | 349 | 317 |
| Temperature Corrections For Difference From: | | | | | | | | | | |
| Design Entering Air Temp, °F | 273 | 280 | 305 | 303 | 271 | | 243 | 351 | 303 | 265 |
| Design Entering Flue Gas Temp, °F | 296 | 305 | 335 | 332 | 295 | | 272 | 380 | 332 | 290 |
| Design X-Ratio, °F | 327 | 307 | 318 | 299 | 315 | | 330 | 293 | 316 | 308 |
| X-Ratio Air Leak Correction, °F | 29 | 52 | 38 | 44 | 34 | | 18 | 36 | 24 | 34 |
| Design Flue Gas Flow Rate, °F | 292 | 300 | 332 | 324 | 287 | | 270 | 362 | 328 | 283 |
| Corrected Outlet Temp, °F | 335 | 332 | 338 | 329 | 337 | | 325 | 319 | 328 | 329 |
| **Secondary Section** | | | | | | | | | | |
| Secondary Air Rate, lb/hr | 497,200 | 481,200 | 498,200 | 531,100 | 539,700 | | 482,100 | 500,900 | 516,300 | 535,400 |
| T In, °F | 89 | 95 | 102 | 94 | 85 | | 94 | 93 | 94 | 83 |
| T Out, °F | 612 | 619 | 588 | 584 | 578 | | 612 | 490 | 596 | 595 |
| Secondary Flue Gas Rate, lb/hr | 649,200 | 636,300 | 659,600 | 655,100 | 658,600 | | 606,200 | 562,300 | 658,200 | 686,500 |
| T In, °F | 675 | 677 | 667 | 659 | 658 | | 671 | 655 | 663 | 661 |
| T Out, °F (Ht. Bal) | 296 | 303 | 321 | 283 | 276 | | 281 | 323 | 290 | 283 |
| Temperature Corrections for Differences From: | | | | | | | | | | |
| Design Entering Air Temp, °F | 291 | 293 | 307 | 274 | 273 | | 271 | 315 | 281 | 281 |
| Design Entering Flue Gas Temp, °F | 298 | 304 | 326 | 290 | 284 | | 284 | 333 | 296 | 290 |
| Design X-Ratio, °F | 264 | 267 | 284 | 268 | 264 | | 260 | 331 | 265 | 257 |
| Design Flue Gas Flow Rate, °F | 297 | 304 | 321 | 283 | 276 | | 284 | 328 | 290 | 281 |
| Corrected Flue Gas Outlet T, °F | 261 | 260 | 276 | 265 | 267 | | 257 | 339 | 262 | 260 |
| **Totally Corrected Temp, °F** | **271** | **270** | **283** | **273** | **276** | | **265** | **336** | **269** | **268** |
| **Approach To Design, °F** | **18** | **17** | **30** | **20** | **23** | | **12** | **83** | **16** | **15** |

(1) Based On CONSOL Method Of Calculating Flue Gas Outlet Temperature Corrections For Deviations From Design X-Ratio And Design Gas Flow.
(2) Test Result Questionable Due To Problem In Measuring The Inlet Flue Gas Composition. See Performance Report For Discussion.
(3) Air Leak From Sootblower Penetrations Assumed To Flow Into Primary Flue Gas Section.

The test results indicate the following:

- Under clean operating conditions, the thermal performance of both heat pipes approached but never met or exceeded the guaranteed flue gas outlet temperature; i.e., the totally corrected flue gas outlet temperature was never equal to or below 253 $^{0}$F. The average combined temperature approach to design for the two heat pipes was 15.7 $^{0}$F ((18±17±12)/3) and 18.5 $^{0}$F ((20±23+16+15)/4) for the first and second clean condition tests, respectively. Based on the CONSOL analysis, the uncertainty in these numbers is about ±4.4 $^{0}$F for a *95%* confidence level.
- When clean, the 2B heat pipe performed slightly better than the 2A heat pipe. For the first clean condition test, the approach to the design flue gas outlet temperature was 12 $^{0}$F for 2B versus 17.5 $^{0}$F (avg.) for the 2A. For the second clean condition test, the approaches to the design flue gas outlet temperature were 15.5 $^{0}$F and 21.5 $^{0}$F for the 2B and 2A heat pipes, respectively.
- During the period when the fouled condition performance was measured, the 2B heat pipe fouled more rapidly than the 2A unit. This is indicated by the higher approach to design flue gas outlet temperature for the 2B heat pipe at the end of the six-month test period; i.e., 83 $^{0}$F for the 2B versus 30 $^{0}$F for 2A and by higher flue gas side pressure drops i.e., 9.0 in. WC for the 2B heat pipe and 5.9 in. WC for 2A (pressure drops corrected to design flow and temperature). Slight differences in the flue gas flow balancing and temperature control between the two heat pipes is likely responsible for the more rapid fouling of the 2B heat pipe during this particular test period. A review of other operating periods indicates a random behavior with respect to which heat pipe fouled quickest.
- Washing the heat pipes was very effective in removing cold-end fouling deposits and recovering thermal performance. This is shown by flue gas side pressure drop recoveries after washing and by the close approach of the totally corrected flue gas outlet temperatures for the clean condition tests.
- The results indicate a slight performance decline for both heat pipes between the two clean condition tests. The approach to the design flue gas outlet temperature increased 4 $^{0}$F (17.5 $^{0}$F avg. increasing to 21.5 $^{0}$F avg.) for the 2A heat pipe and 3.5 $^{0}$F (12 $^{0}$F increasing to 15.5 $^{0}$F avg.) for the 2B unit. This loss in performance, may or may not be real since it falls within the ±4.4 $^{0}$F uncertainty of the analysis procedure. If the decline is real, it may be due to a slight difference in the heat transfer surface fouling between the two tests or to loss or deterioration of some heat transfer fluids. Longer term performance monitoring is needed to establish if there is a trend.

## AIR LEAKAGE

The all welded construction of the heat pipe air heaters prevents air leakage from the higher pressure primary and secondary air sections into the flue gas sections. The modules are seal welded together and all tubes are welded to the divider plate which separates the flue gas and air sections. Baring cracked or missing welds, no leakage should occur. However, because the flue gas sections operate at nominally 10 in. WC to 15 in. WC negative pressure, significant amounts of air can be drawn into the heat pipes through check valves on the sootblowers and at the sootblower wall penetrations. The check valves allow a continuous ambient air purge to sweep fly ash and flue gas from the lances when the sootblowers are inactive. The leak at the wall penetrations is due to the designed-in, loose-fit (3/32” annular gap) between the sootblower lance and the wall seal ring.

The ASME air heater performance code was followed to determine the total leakage associated with the ambient air infiltration. This was done by determining the inlet and outlet flue gas flow rates and then subtracting the inlet rate from the outlet rate. The results for the May and November 1996 clean condition tests is presented in Table 4.11-3 as a percentage of the inlet flue gas flow. By the code procedure, the gas rates are calculated based on the measured inlet and outlet flue gas compositions, the measured coal feed rate, and the coal composition.

**TABLE 4.11-3**
**MEASURED AIR LEAKAGES, WT % OF INLET FLUE GAS FLOW**

| **Heat Pipe** | | **2A** | | **2B** | |
|---|---|---|---|---|---|
| Date | Boiler Load MW | Total Leakage | Unaccounted Leakage | Total Leakage | Unaccounted Leakage |
| 5/14/96 | 149 | 2.7 | 1.9 | ND | ND |
| 5/15/96 | 147 | 4.4 | 3.6 | 1.4 | 1.2 |
| 11/7/96 | 147 | 2.5 | 2.4 | 1.2 | 1.0 |
| 11/8/96 | 148 | 2.4 | 2.2 | 2.2 | 2.1 |
| Average | | 3.0 | 2. 5 | 1.6 | 1.4 |

During both clean condition tests, the lance purges for all 32 sootblowers were measured by sealing one end of a 2 inch diameter plastic tube around the lance check valves and using a mini-pitot tube to measure the air velocity through the tube. The total purge rates averaged 2,680 lb/hr or about 84 lb/hr per sootblower. This is typically less than 0.18% of the inlet flue gas flow at full load (nominally 1,500,000 lb/hr). Similar measurements at the sootblower wall penetrations were not possible due to equipment clearances. The leak at the wall penetrations was taken to be the unaccounted for leak. This is the difference between the total leak rate determined by the ASME code and all air in flows which can be accounted for, such as, the lance purge flows and the air consumption of the infrasonic cleaner (4,800 lb/hr for the 2A heat pipe only, for some tests).

As shown in table 4.11-3, the leak rates are quite low for the heat pipes. Total leakages averaged 3.0 wt % and 1.6 wt % of the inlet flue gas flow for the 2A and 2B heat pipes, respectively. The uncertainty in the leak rate is about ±1.6 wt % absolute. Similarly, the unaccounted leakages, which are taken to be mainly the leak at the sootblower wall penetrations, averaged 2.5 wt % and 1.4 wt % for the 2A and 2B heat pipes, respectively. The somewhat higher leak rates for the 2A heat pipe may be due to differences in wear/fit of sootblower lance wall seal rings or the presence of other leaks, such as, leaks at manway door seals.

## UNIT PRESSURE DROPS

Checks were made of the guaranteed pressure drops for both air heaters during the clean condition performance tests. To insure accuracy of the differential pressure measurements, special pressure taps were installed on the heat pipe casing per ABB/API instructions. These taps consisted of two 1/8" diameter holes drilled through the casing and spaced horizontally one foot apart. The holes were de-burred to prevent turbulence at the inside wall opening. Each tap pair was "Y'ed" together and then connected to the appropriate side of a liquid manometer for differential pressure measurement.

The operating pressure drop checks were done in accordance with the ASME PTC 4.3 code procedures. These procedures correct the measured pressure drops for deviation from design gas or air flow and temperature. The design pressure drops are:

| | |
|---|---|
| Flue Gas | 3.65 in. WC |
| Primary Air | 3.60 in. WC |
| Secondary Air | 5.35 in. WC |

Measured performance results are presented in table 4.11-4 as a percent of design. The results show that the actual performance essentially met or exceeded the design.

**TABLE 4.11-4**
**PERFORMANCE SUMMARY -- HEAT PIPE PRESSURE DROPS**
**CLEAN CONDITION TESTS**

| **Unit 2A** | **Boiler Load** | **Fully Corrected Pressure Drops, % of Design** | | |
|---|---|---|---|---|
| Date | MW net | Flue Gas | Primary Air | Secondary Air |
| 5/14/96 | 149 | 98% | 74% | 106% |
| 5/15/96 | 147 | 99% | 73% | 110% |
| 11/7/96 | 147 | 95% | 86% | 99% |
| 11/8/96 | 148 | 94% | 73% | 98% |
| | Average | 97% | 76% | 103% |
| Unit 2B | | | | |
| 5/14/96 | 151 | 106% | 75% | 104% |
| 5/15/96 | 147 | 107% | 78% | 102% |
| 11/7/96 | 147 | 101% | 96% | 99% |
| 11/8/96 | 148 | 95% | 87% | 94% |
| | Average | 102% | 84% | 100% |

### 4.11.4 CORROSION MONITORING PROGRAM

Previous work done by EPRI and NYSEG had demonstrated that the CAPCIS corrosion monitoring system could be used in condensing environments, such as the flue gas streams in and around utility air heaters. NYSEG purchased two CAPCIS electrochemical corrosion probes and DOS based VISICOR software to log and graphically present the data as part of the preliminary testing done to select materials of construction for the Milliken heat pipe air heaters. The testing included monitoring corrosion rates in two pilot heat pipes, one at EPRI's Environmental Control Technology Center, the other at NYSEG's Milliken Station, and corrosion monitoring in the ductwork ahead and down stream of the Milliken Unit 2 precipitator. To reduce the preliminary test costs, probe temperature control hardware and field data acquisition/signal processing electronics were borrowed from EPRI. The experience gained with this equipment indicated that the corrosion probe system was sensitive to changes in corrosion rates and that after calibration, could provide reasonable accurate estimates of the actual corrosion rates.

As part of the CCT-IV test program, NYSEG committed to installing and testing an on-line, real-time corrosion monitoring system supplied by CAPCIS March Ltd. Two air-cooled corrosion probes, (Cor-Ten A®, SA-178A carbon steel) were installed at the outlet of the Milliken Station 2B heat pipe and two passive (not air-cooled) wall corrosion probes (SA-178A CS) were installed in the ductwork just ahead of the Unit 2 FGD scrubber. This probe combination allowed for corrosion monitoring of the actual materials of construction in the expected severest condition locations. The air-cooled probe temperatures were controlled to match or be off-set from the temperatures of cold-end heat pipes which had been fitted with thermocouples. This provided a means of maximizing heat recovery by operating at the lowest flue gas outlet temperatures consistent with low corrosion rates. After gaining confidence in the monitoring system, the intent was to use the corrosion probe signals to control the secondary air by-pass damper in the heat pipe.

NYSEG had CAPCIS refurbish the air-cooled corrosion probes and purchased all new temperature control hardware, field electronics, and software. At the time of purchase, CAPCIS was significantly revising their corrosion monitoring systems. Field electronics were redesigned and the DOS software was replaced with a graphical interface UNIX based database system. These changes created many hardware and software problems which are being addressed at the time of this writing. Currently, there is insufficient historical data on either the air-cooled or the passive probes to draw any conclusions concerning corrosion monitoring. At this time, CAPCIS (now Integriti Solutions) is standing behind their equipment and is working with NYSEG to provide an operable, debugged monitoring system.

### 4.11.5 OPERABILITY AND RELIABILITY

#### HISTORY

Table 4.11-5 summarizes the operations history for the heat pipe air heaters. A more detailed history is presented in Appendix G of the Heat Pipe Final Report. Between June and December 1994, the Unit 2 boiler was off line to allow rebuilding and upgrading of the electrostatic precipitator particulate collectors, construction and tie-in of the SHU flue gas desulfurization system, and installation of the heat pipe air heaters. The Unit 2 boiler was placed back in service on December 11, 1994.

The initial operations indicated that the heat pipe air heaters were not performing up to design expectations i.e., the full load flue gas outlet temperatures were in range of 270-290 $^0$F compared to expected temperatures of 250-260 $^0$F. In late January 1995, ABB/API obtained field data which confirmed these results. The field data also indicated that there were problems with the inlet air side flow distributions. To correct the problems and allow further analysis, ABB/API recommended (1) installation of additional tube diagnostic thermocouples (TCs), (2) installation of special condenser-end baffles to help redirect flue gases traveling down the heat pipe walls back into the tube bundles, and (3) the sampling of selected heat pipe tubes to determine if the heat transfer fluid had deteriorated.

Initial repairs were made to the heat pipes between February 27 and March 3, 1995, during a boiler shutdown to clean turbine screens. The recommended ABB/API TCs were installed; perforated plates were added to the primary air and FD fan discharges to improve the air flow distribution to the heat pipes; condenser end baffles were installed in the primary section of the 2B heat pipe; and the contents of several tubes were sampled. One hundred and ten tubes were evacuated and resealed. After the boiler was back in service, the operation improved for the primary air heating section of the 2B heat pipe.

An ABB/API analysis of heat pipe contents indicated that non-condensable gases containing hydrogen, carbon dioxide, and ethylene were being generated in the naphthalene tubes. An analysis done by CONSOL of fresh naphthalene and “used” naphthalene from the Milliken air heaters indicated that certain contaminants in the naphthalene were decomposing and generating the gases. To eliminate the non-condensing gases, ABB/API recommended that the heat pipes with naphthalene be re-evacuated under cold conditions and momentarily vented under hot conditions. This procedure would correct the problem assuming that the contaminant decomposition was a one time event.

Heat pipe repairs and modifications were effected by ABB/API during the two week outage beginning September 15 to October 2, 1995. By October 5, 2,400 tubes were evacuated, hot vented, and resealed. When the units were again in operation, ABB/API evaluated the performance and notified NYSEG that the heat pipes were performing as designed and recommended that a performance test be conducted within 60 days.

# TABLE 4.11-5
# MILLIKEN HEAT PIPE AIR HEATER OPERATIONS SUMMARY

| | |
|---|---|
| | **1994** |
| 6/18 - 12/11 | Unit 2 outage to rebuild and modify the ESP, SHU scrubber tie-in, and heat pipe installation. |
| 12/11 | Start up of boiler, heat pipe put into service. |
| | **1995** |
| 1/25 - 1/27 | ABB/API obtains field data on heat pipe performance. Thermal performance is less than expected. Flue gas outlet temperatures are higher than design. |
| 2/27 - 3/3 | Initial repairs made to the heat pipes (installed perforated distribution plates on primary and secondary air fan outlets, installed special condenser end baffles in the primary section of the 2B heat pipe, checked vacuum on approximately 110 tubes). |
| | When heat pipes were back in service, the operation of unit 2B primary air heating section improved. |
| | ABB/API’s analysis of the gas from naphthalene tubes reveals that high levels of **2’ 2** and ethylene are being generated. |
| 5/16 | CONSOL analysis of naphthalene samples indicates that two low level contaminants in the naphthalene are breaking down and are likely responsible for the non-condensable gases found by ABB/API in the naphthalene tubes. |
| 9/15 - 10/2 | ABB/API repaired both heat pipes. Vented and resealed 2,400 naphthalene containing tubes to remove non-condensable gases. |
| 10/2 - 3/15/96 | Operation of heat pipes monitored. Repairs resulted in improved performance. Performance observed to gradually decline due to cold-end fouling. Sootblowers not effective in keeping units clean. |
| | **1996** |
| 3/15 - 4/3 | Heat pipes washed. Low frequency (infrasonic) cleaner installed on Unit 2A heat pipe. |
| 5/13 - 5/17 | First detailed air heater performance tests conducted. |
| 7/19 | Ceased operation of the infrasonic cleaner due to development of cracks in the inlet ductwork to the 2A ESP. |
| 8/30 | Placed infrasonic cleaner back in service at 75% of full power. |
| 9/6 | Began operating infrasonic cleaner at full power again. |
| 10/7 - 10/8 | Detailed fouled condition heat pipe performance tests conducted. |
| 10/11 -10/18 | Shutdown Unit 2 boiler for heat pipe cleaning and repair of fatigue cracks in the 2A ESP inlet ductwork. Ductwork stiffened. |
| 11/7 - 11/8 | Second detailed clean condition heat pipe performance tests conducted. |
| | **1997** |
| 3/31 - 4/20 | Unit 2 boiler off-line for annual outage. Heat pipes cleaned. Operation of infrasonic cleaner was discontinued because cracks were found in division wall separating the primary and secondary flue gas sections in the 2A heat pipe. |
| 10/24 - | 10/31 Unit 2 taken off line -- convenient time for heat pipe cleaning. |
| | 1998 |
| 4/24 | Unit 2 boiler off-line for annual outage. |

To ensure that continued decomposition of naphthalene contaminants would not be a problem, the performance tests were deferred. Additionally, there was concern that the heat pipes were not clean enough for a guarantee performance test. The boiler outage schedule had allowed time for only a partial washing of the heat pipes. A complete washing was not done until April 1996.

Between October 2, 1995 and March 15, 1996, the performance of both heat pipes gradually deteriorated due to cold-end fouling. The flue gas side outlet temperatures and the pressure drops across the tube banks both increased. Unit 2 was shut down between March 15 and April 3, 1995 for water washing of the heat pipes and to allow installation of an infrasonic cleaner (InfraSonik$^{TM}$), on the 2A heat pipe. For comparison, the 2B heat pipe air sootblowers were fitted with special expanding nozzle jets.

NYSEG and CONSOL conducted the first detailed ASME Code procedure performance tests between May 13, and May 17, 1996. These tests were not observed by ABB/API personnel since they felt that the units had not been cleaned sufficiently. The performance results were, however, the best obtained during the test program.

When first placed in service, the infrasonic cleaner was operated continuously at full power level. This appeared to stave off fouling in heat pipes, particularly within the 2A unit. However, because of the intense sound level (140 dB) within the equipment, resonation caused cracks in the ductwork between the 2A heat pipe outlet and the 2A ESP inlet. The infrasonic cleaner was then taken out of service for approximately 1.5 months (7/19/96 to 8/30/96) until temporary repairs could be made to the ductwork. The unit was placed back in continuous service at three-fourths power on August 30, 1996. Fouling of both heat pipes appeared to intensify after the infrasonic cleaner was placed back in service. However, it is not known if the apparent increase in fouling was caused by the sudden sloughing of deposits which had been laid down while the infrasonic cleaner was out of service, or to increased acid/fly ash deposition due to the change over to a higher sulfur coal. Commencing on September 6, 1996 the infrasonic cleaner was again operated at full power. This did not appear to reduce the fouling or fouling rate.

On October 7, and October 8, 1996 heat pipe tests were again conducted to establish the fouled condition performance after approximately six months of continuous operation. The tests showed that the 2A heat pipe with the infrasonic cleaner, was somewhat less fouled and operating better than the 2B heat pipe. However, the thermal performance of both heat pipes had degraded significantly and flue gas side pressure drops were high. The Unit 2 boiler was taken out of service between October 11, and October 18, 1996 for heat pipe washing and SHU absorber cleaning. During this period, the ductwork between the 2A heat pipe and the ESP inlet was stiffened to eliminate vibration caused fatigue fractures. The stiffening was accomplished by internally bracing the vertical ductwork using sixty-six, four inch diameter pipes welded to opposing walls. This eliminated resonances and further cracking of the ductwork.

On October 17, 1996, representatives of NYSEG, ABB/API, and CONSOL R&D

inspected the washed heat pipes. One small area with some deposition was located in the 2B heat pipe. After this area was cleaned, all parties agreed that the units were clean and ready for testing. Performance tests were then scheduled and conducted on November 7 and November 8, 1996. These tests served a dual purpose of being both guarantee performance tests and tests which demonstrated thermal performance recovery following cleaning. The tests were the last detailed performance tests conducted during the demonstration program. Operations of the heat pipes were followed using computer logged process data for the remainder of the test program.

An annual outage for the Unit 2 boiler occurred between March 31 and April 20, 1997. During the outage, the heat pipes were inspected and cleaned. Cracks were found in the division walls between the primary and secondary flue gas sections in the 2A heat pipe. The continuous operation of the infrasonic cleaner was apparently responsible for the damage. The cracks were repaired by welding and the operation of the infrasonic cleaner was discontinued.

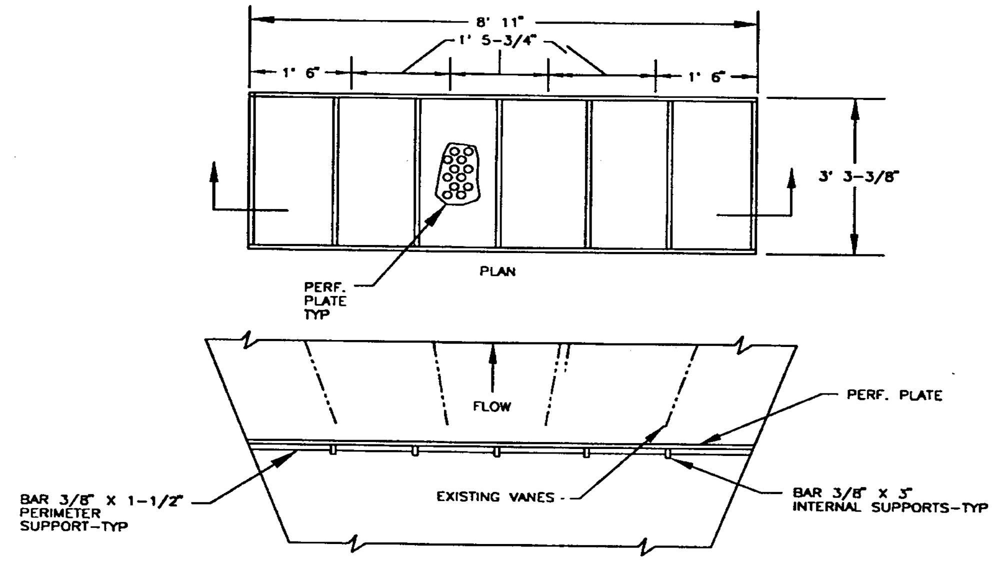
After the annual outage, the Unit 2 boiler and heat pipes were placed back in service on April 20, 1997. Throughout 1997, the heat pipe air heaters were operated in a normal fashion. Except for one short boiler outage in May to fix a superheater tube leak, Unit 2 remained in service until October 24, 1997 when it was convenient to water wash the heat pipes. Between October 31, 1997 and April 24, 1998, the Unit 2 boiler and heat pipe air heaters were again operated in the normal fashion with no major operating problems experienced.

## PRIMARY/SECONDARY AIR DISTRIBUTION PROBLEMS

After initial operations indicated below design performance for the heat pipe air heaters, ABB/API obtained diagnostic performance data on the units during the last week of January 1995. Analysis of the secondary air outlet temperature data indicated a north-south bias in the temperature distributions. The temperature biasing for the A and B heat pipes appeared to be mirror images indicating that the non-uniform discharge velocity profiles of the FD fans might be responsible. Additionally, primary air temperatures within the upper sootblower lanes showed steep drop-offs with distance from the partition plate (distance from the evaporator end). This indicated the possible presence of non-condensing gases in the hottest heat pipes.

To help flatten the fan velocity profiles, ABB/API recommended installation of perforated plates at the primary air and secondary air (FD) fan outlets. The original heat pipe flow modeling study recommended similar distribution plates (see Appendix C of the Heat Pipe Final Report ). Figures 4.11-2 and 3 show how the perforated plates were installed.

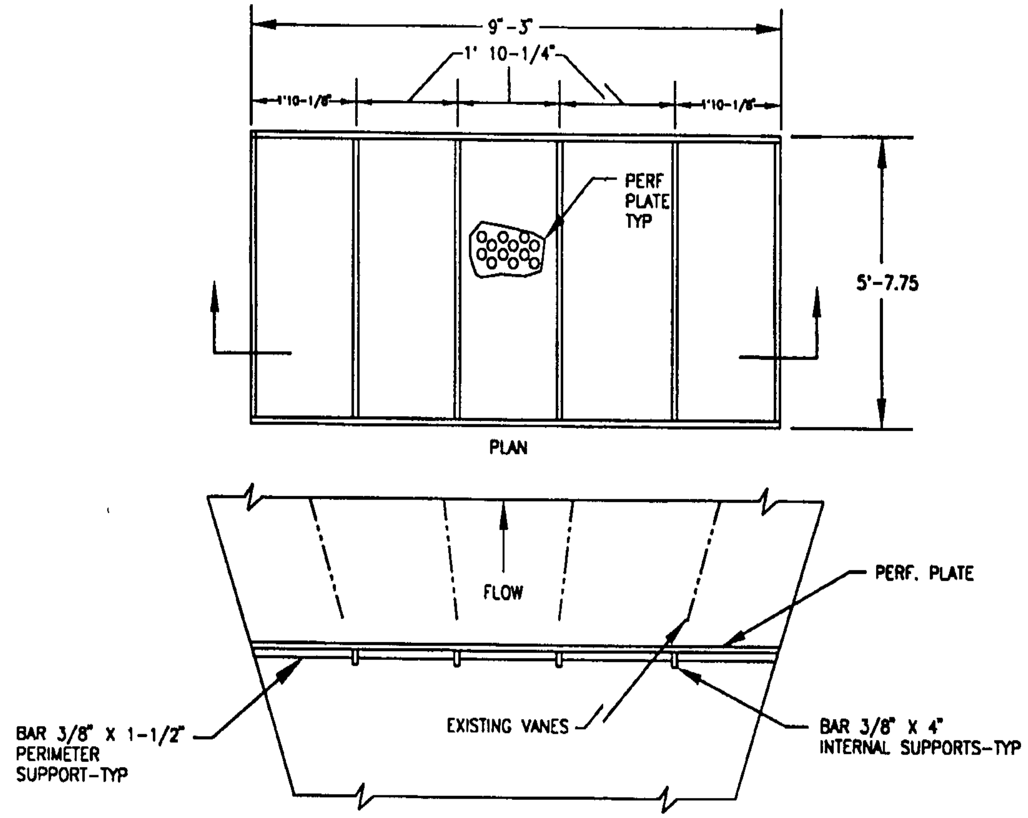
## FIGURE 4.11-1
## PERFORATED PLATE INSTALLATION IN THE PRIMARY AIR FAN DISCHARGE DUCT



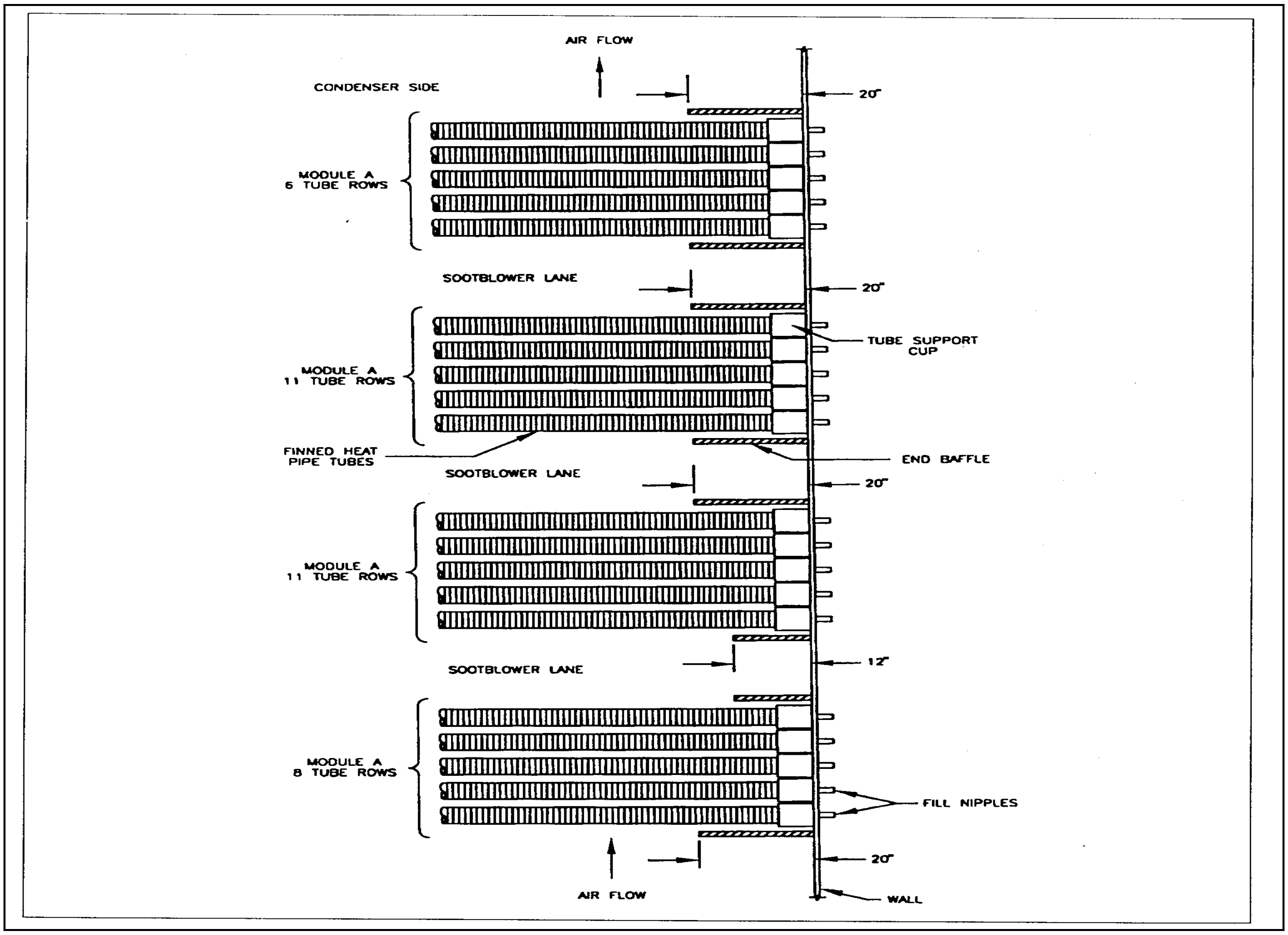
Small amounts of non-condensable gas in heat pipes are often unavoidable due to the presence of trace contaminants in the working fluids and/or the breakdown of the contaminants. In an operating heat pipe the non-condensing gases are forced to the top end of the condenser tubes. This creates a dead zone where little heat transfer takes place. To improve the overall heat transfer performance, ABB/API recommended installation of short (12" to 20" wide) condenser end baffles. The baffles force air flowing across the dead zones back into the center of the heat pipes where the air can be heated. The baffle installation is shown in figure 4.11-4. Baffles were installed in both the primary and secondary air heating sections of both heat pipes.

The effects of the perforated air distribution plate and condenser-end baffle modifications cannot be isolated. The changes were made simultaneously along with the re-evacuation of the naphthalene filled tubes to remove non-condensable gases. However, the combination of changes improved the heat pipe thermal performance and reduced the north-south outlet temperature bias of the secondary air from the air heaters. The original ABB/API measurements taken in January 1995 showed an average north-south temperature difference of about 40 $^0$F. Data taken during the first performance test in May 1996 with the air heaters in a clean condition, indicate average temperature differences of only 11$^0$F-16$^0$F.

## FIGURE 4.11-2
## PERFORATED PLATE INSTALLATION IN THE FD FAN DISCHARGE DUCT



## FIGURE 4.11-3
## CONDENSER END BAFFLE INSTALLATION



## HEAT TRANSFER FLUID DEGRADATION

Based on the results of the January 1995 heat pipe air heater diagnostic tests, ABB/API elected to measure the pressures in selected heat pipe tubes and to analyze the vapor components. During the February 27 to March 3, 1995 Unit 2 shutdown, ABB/API checked the vacuum in approximately 110 tubes. Many of the tubes with naphthalene working fluids had internal pressures exceeding the naphthalene vapor pressure indicating the presence of non-condensable gases. Analyses of the gas revealed high levels of hydrogen (60-65 vol %), carbon dioxide (18 vol %), and ethylene (18 vol %).

ABB/API specified 99.95 wt % purity for the naphthalene used in the heat pipes. However, some naphthalene at 99.5 % purity was later determined to have been received. When it was known that non-condensable gases were being generated, NYSEG requested samples of fresh unused naphthalene, used naphthalene from the heat pipes, and thionaphthene, the contaminant suspected of causing the gas generation. CONSOL R&D analyzed the samples by gas chromatograph mass spectroscopy (GC/MS). The results, which are presented in Appendix I of the Heat Pipe

Final Report, showed that the thionaphthene concentrations in the fresh and used samples were quite similar indicating that thionaphthene was not decomposing and was not likely responsible for the gas generation. The more likely cause was decomposition of two unidentified compounds which were found in the fresh but not in the used naphthalene. Subsequent analyses indicated that there were no strong inorganic acids in either the fresh or used naphthalene which could have reacted with the heat transfer fluid or heat pipe tube metal to generate non-condensable gases.

To eliminate the gas generation problem, ABB/API proposed to install valves on the heat pipe fill stems so that the naphthalene tube could be re-evacuated under cold conditions. Then, to vent the heat pipes under hot conditions to remove gases forced to the top of the condenser end. Since the unidentified compounds boiled at temperatures below naphthalene, this procedure had a high potential of success. During the September to October 1995 shutdown of Unit 2, ABB/API vented and resealed 2,400 naphthalene containing tubes.

When Unit 2 was back in service, ABB/API determined that the heat pipes were working as designed and recommended performance testing within 60 days. The first clean condition performance tests were, however, not conducted until May 1996. This insured against an overly optimistic performance result by providing some additional time for any remaining contaminants in the naphthalene to decompose. A second clean condition test was conducted in November 1996. The ABB/API re-evacuation/hot vent procedure appears to have been successful in removing the naphthalene contaminants since where was only a small deterioration in thermal performance between the two heat pipe tests. The thermal performance decline amounted to a $2^0$F to $5^0$F increase in the totally corrected flue gas outlet temperature. Alternate explanation for the small performance decline include: test result variation (the result difference is about equivalent to uncertainty level), the possibility of a difference in fouling level, or as will be discussed in the next section, loss of some of the naphthalene fill fluid.

## NAPHTHALENE LEAKS

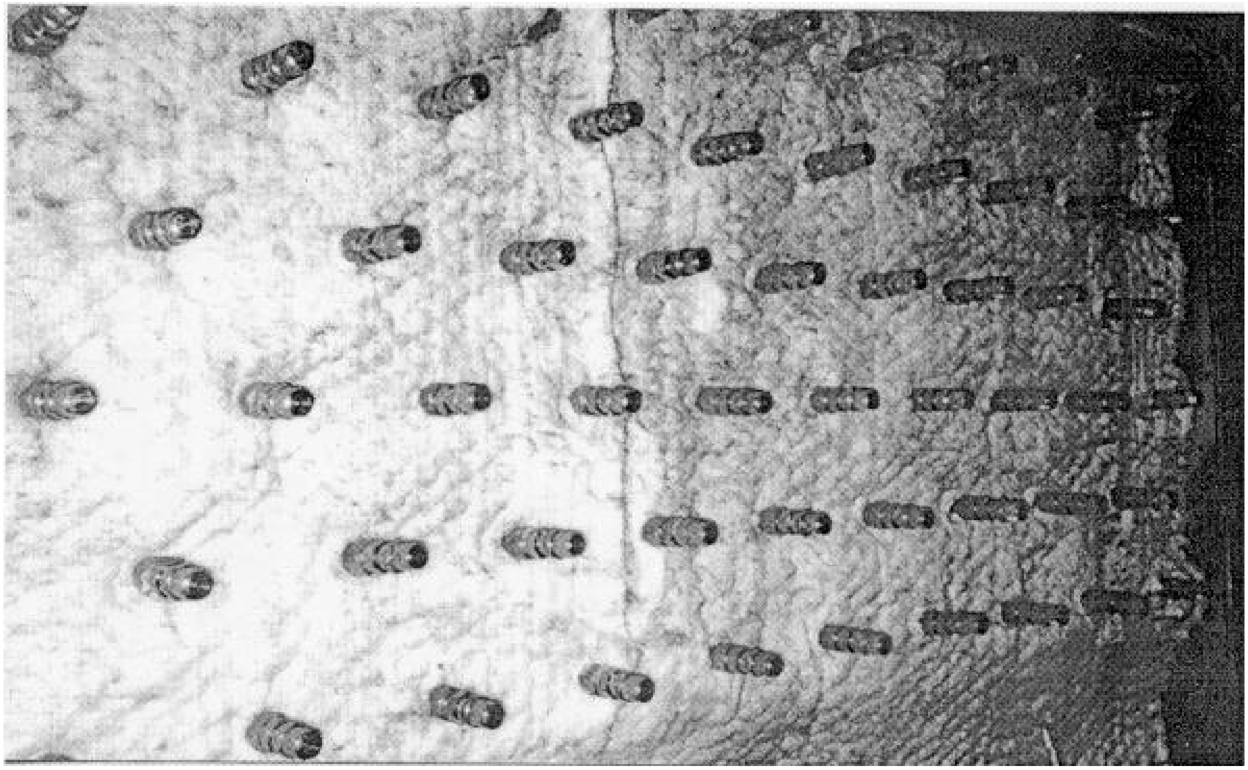
Working fluid leakage was not a concern or a problem for the heat pipes as originally constructed. The individual heat pipes had an all-welded construction with seal welded end caps and crimped and seal welded fill tube connections. Leakage became a concern to NYSEG after the naphthalene filled tubes were modified to remove the buildup of non-condensable gases as discussed in the previous section. ABB/API recommended and installed Swagelok “P” series purge valves with short capped extension nipples on each heat pipe that contained naphthalene. These modifications allowed removal of the non-condensable gases from the heat pipes and future re-venting should additional gas generation take place.

After the modifications were made, there was a strong naphthalene odor in the plant. There had been no such odor prior to the modifications. Because of this, NYSEG instituted a naphthalene monitoring program. There was concern that some or all the modified tubes were leaking and with time would become exhausted of heat transfer fluid.

Figure 4.11-5 shows the end of a modified heat pipe tube sheet with the capped fill tube nipple extensions protruding through soft insulation. The insulation covers the fill tube purge valves. Under normal conditions, the tube sheets ends are covered by casing panels. To check for naphthalene leaks, test ports were added to the casing panels. Each port consisted of a capped pipe nipple extending from the casing panel through the external insulation and the corrugated lagging. One test port was installed for each naphthalene module, three ports in the primary sections and four ports in the secondary sections of each heat pipe.

Naphthalene leak measurements were made using a Photovac Microtip HL-200 analyzer calibrated with 98.5 ppm isobutylene. The analyzer measures the presence of hydrocarbons using a photo ionization detector. The amount of naphthalene was determined from the instrument output and a relative response factor for naphthalene. Typically, the sampling procedure was to open a port for 10 seconds, sample for 10 seconds and take a reading.

**FIGURE 4.11-4**
**MODIFIED FILL NIPPLES ON HEAT PIPES WITH NAPHTHALENE WORKING FLUID**



The leak check results are presented in table 4.11-6. For the first four sampling periods, the data indicate an overall higher leak rate for the 2A heat pipe compared to the 2B heat pipe. Most importantly, the last sampling data (December 9, 1997) suggests that the leaking tubes in both heat pipes have become exhausted. This may mean that all of the originally leaking tubes are now empty and that there will be no additional affect on the heat pipe thermal performance. This remains to be proven. Continued periodic leak check monitoring will be needed to determine if the system has stabilized.

**TABLE 4.11-6**
**NAPHTHALENE LEAK CHECK MEASUREMENTS**

| | | Naphthalene Concentrations, ppm | | | | |
|---|---|---|---|---|---|---|
| Heat Pipe | Module(1) | *5/21/96* | 9/18/96 | 10/28/96 | 3/4/97 | 12/9/97 |
| 2A | AI | 1,400 | 8,100 | ≥2,000 | 3,000 | 66 |
| 2A | A2 | 87 | 24 | >30 | 50 | 8 |
| 2A | A3 | 265 | 230 | >700 | 400 | 22 |
| 2A | B1 | 76 | 360 | ≤5 | 200 | 22 |
| 2A | B2 | 28 | 230 | <100 | 400 | 18 |
| 2A | B3 | 95 | 0 | <10 | 30 | 1.5 |
| 2A | C3 | 0 | 0 | 0 | 0 | 0 |
| 2B | AI | NS | 0 | >400 | 70 | 20 |
| 2B | A2 | NS | 0 | 0 | 0 | 0 |
| 2B | A3 | N/I | N/I | 0 | 0 | 0 |
| 2B | B1 | 95 | 0 | ≥100 | 300 | 8 |
| 2B | B2 | N/I | N/I | >100 | 0 | 0 |
| 2B | B3 | N/I | N/I | 0 | 20 | 0 |
| 2B | C3 | 86 | 360 | >200 | 550 | 0 |

(1) See Figure 7.

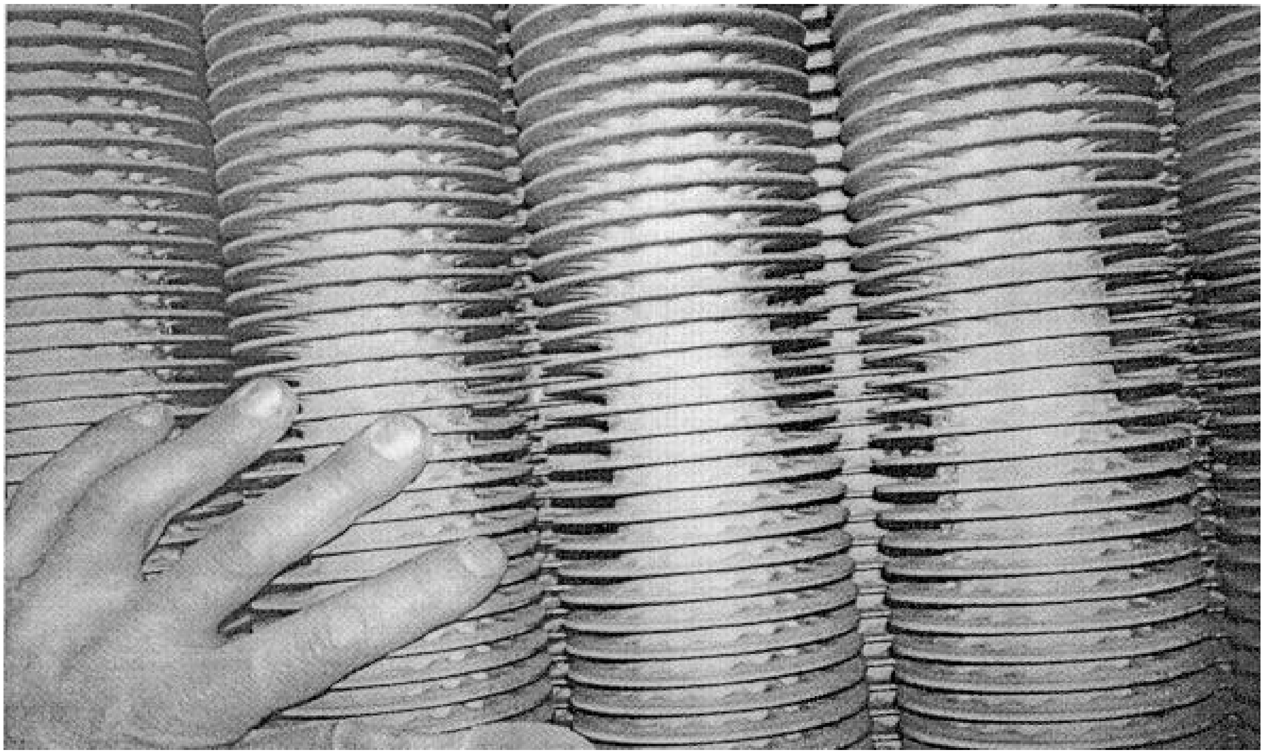
NS - Not sampled, N/I - Port not installed

## COLD-END FOULING

The heat pipes are constructed with four levels of tube banks (modules). Since the flue gas flow through the air heaters is downward, the bottom tube banks are the cold-end modules. As with Ljungstrom® and tubular air heaters in coal-fired service, these cold-end sections tend to gradually foul. The Milliken heat pipe cold-end deposits contained high levels of sulfur (14 wt %) indicating that the fouling is caused by sulfur trioxide ($SO_3$) condensation from the flue gases (see the fouled condition performance report in Appendix F of the Heat Pipe Final Report). Condensing $SO_3$ reacts with water vapor forming a sticky sulfuric acid liquid which traps fly ash. Gradually, fly ash/acid deposits build up in the cold-end module restricting the flue gas flow through the unit. The fouling is dependent upon the amount of $SO_3$ in the flue gases, the cold end metal temperatures, and the effectiveness of the sootblowing.

At Milliken, the heat pipes are washed approximately every six months to remove the cold-end deposits. In all but the cold-end modules, the heat pipes on the flue gas side appear as shown in figure 4.11-6 with tubes and fins free of deposits. Normally, most of the top side of the cold-end tube bank will also be free of deposits. However, in some localized areas, deposition appears as shown in figure 4.11-7 indicating the beginning of the fouling zone. Figure 4.11-8 shows the typical condition of the cold-end module as seen from the bottom. Throughout the module, deposition occurs mostly on the top side of the tubes due to the direct impact from the downward flowing flue gases and fly ash. The deposition appears to increase with depth as the flue gases flow through the tube bank and progressively contact colder heat pipes. Figure 4.11-9 shows the tube bank after cleaning. When clean, a light placed below the cold-end module can be seen (bottom center) through the eight row deep tube bank.

**FIGURE 4.11-5**
**TYPICAL CONDITION OF HEAT PIPE TUBES IN THE TOP THREE MODULES**



Increasing flue gas side pressure drop and flue gas outlet temperature are signs of cold-end fouling. Figure 4.11-10 shows typical flue gas side pressure drops for the heat pipe air heaters under high load conditions. All pressure drops are corrected to a common basis. Breaks in the plots indicate the times when the Unit 2 boiler was off-line for maintenance. During these periods, the heat pipes were washed to remove the cold-end deposits. Figure 4.11-10 shows that for one or both heat pipes the flue gas side pressure drops generally increase to high levels in five to six months after cleaning. The figure also shows that the baseline pressure drop of about 4 in. WC is recovered following each full cleaning. Clearly, for the last four wash operations, equivalent cleanliness was achieved for the two heat pipes. The reader may note that the baseline pressure drops are slightly higher (0.1 in. WC -0.5 in. WC) than the pressure drops reported for the performance tests. This is mostly due to differences in measuring equipment and pressure tap location for the plant process control system versus the special high accuracy taps and instrumentation used for the performance tests. The differences are not significant for the day-to-day system performance monitoring.

### FIGURE 4.11-6
### FOULED AREA ON INLET FLUE GAS SIDE OF THE BOTTOM COLD-END HEAT PIPE MODULE

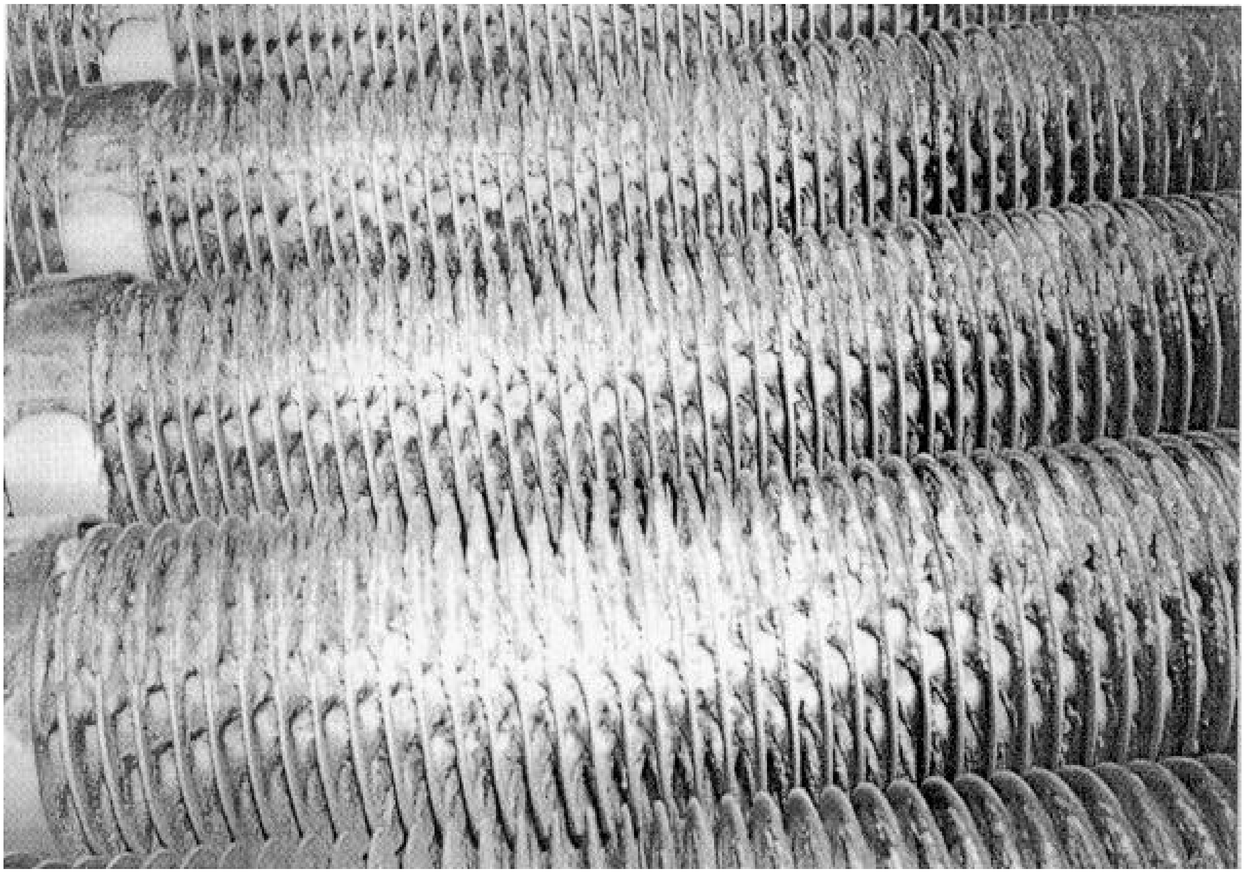


**FIGURE 4.11-7**
**BOTTOM VIEW OF COLD-END TUBE BANK SHOWING DEPOSITS ON TOP SIDE OF TUBES**

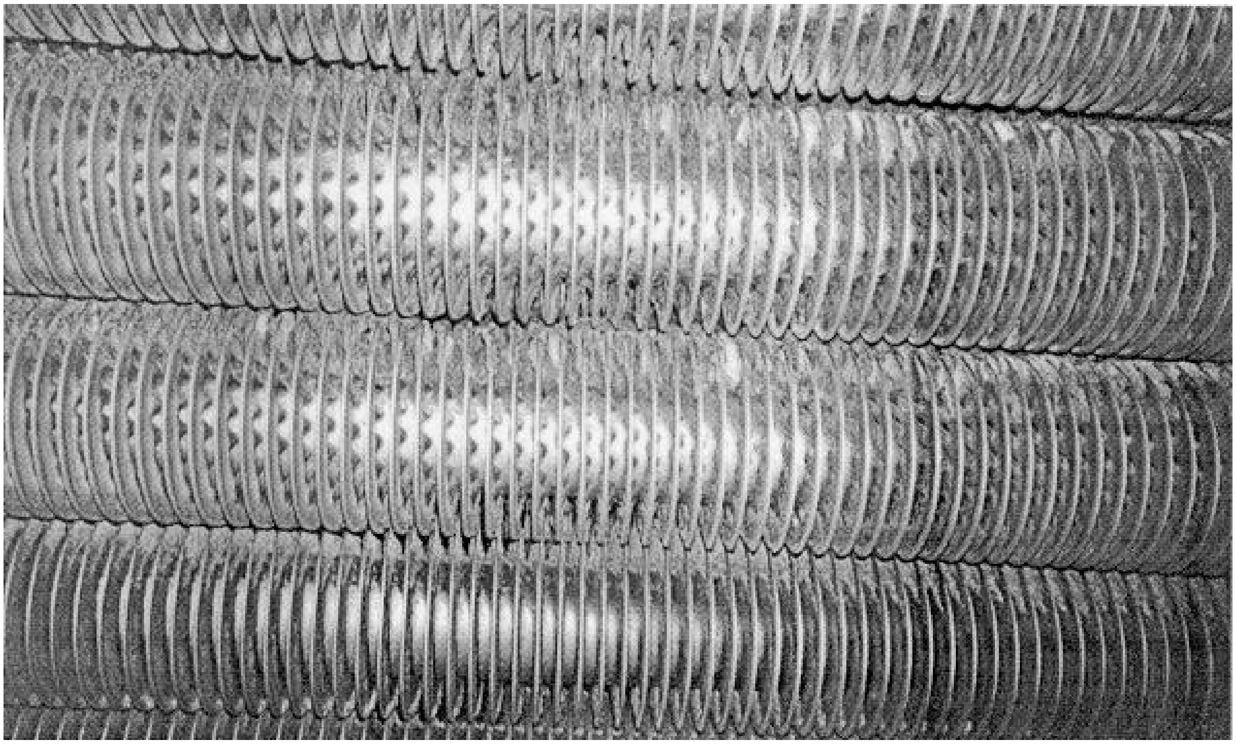
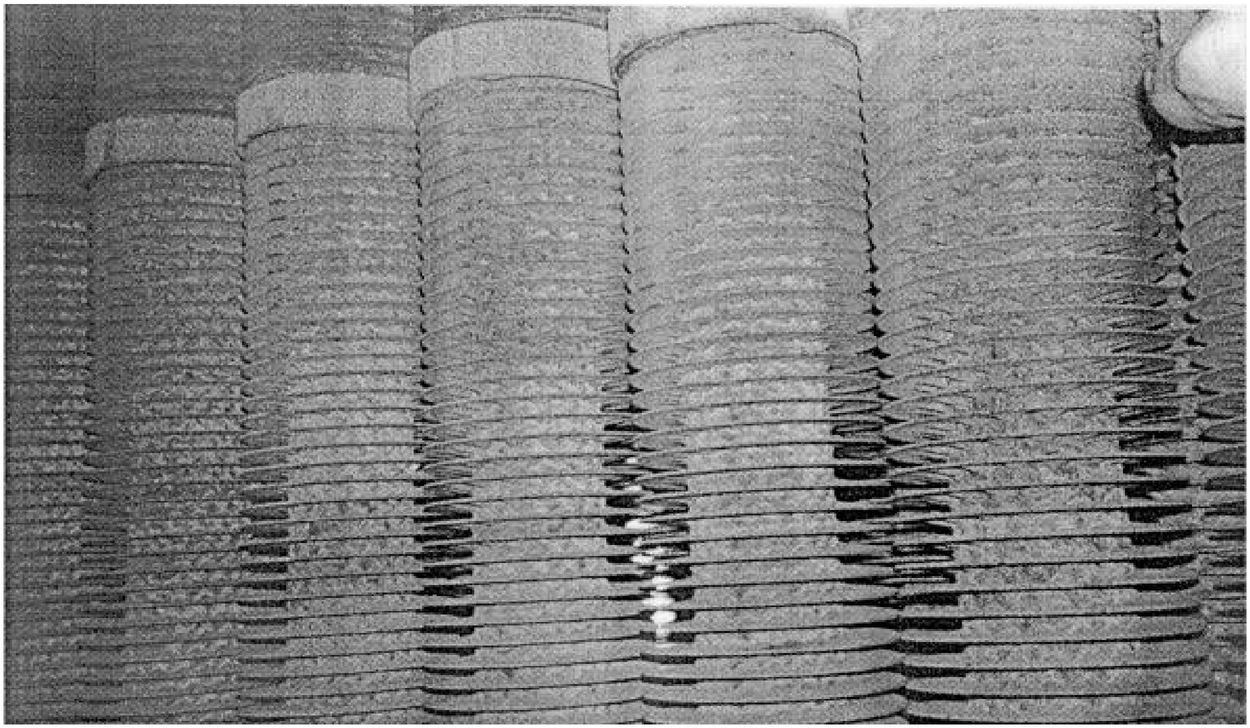
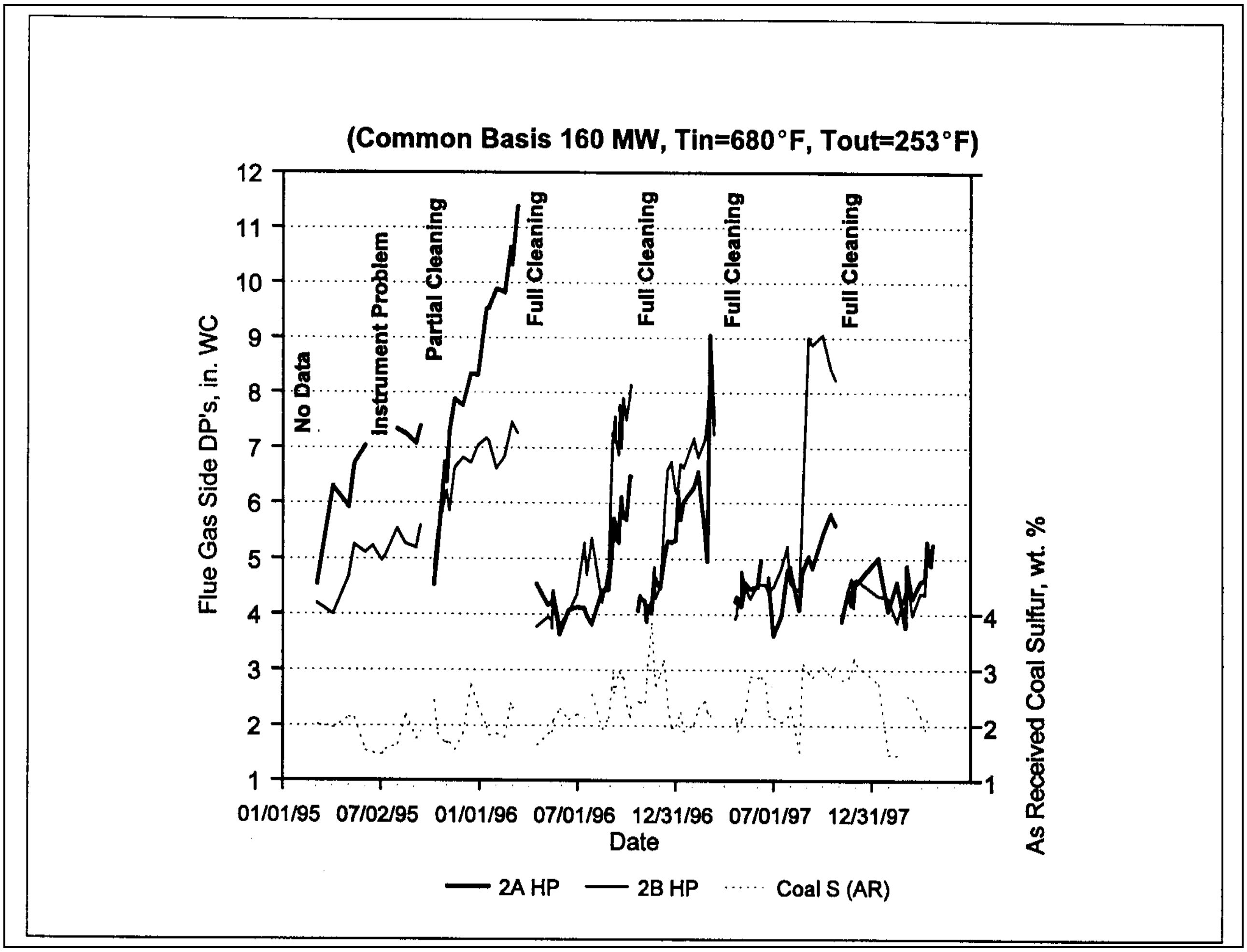


**FIGURE 4.11-8**
**BOTTOM COLD-END HEAT PIPE TUBE MODULE AFTER CLEANING**



For the last operating period shown in Figure 4.11-10, the heat pipe pressure drops were better behaved and did not yet shown the typical high pressure drop increase. This may be attributable to instituting a practice of not operating the boiler at less than 80 MW load and more attention to balancing heat pipe flows and temperatures. These operating practices help to avoid excessively low cold-end temperatures in the heat pipes which promote fouling.

**FIGURE 4.11-9**
**FLUE GAS SIDE PRESSURE DROPS AND COAL SULFUR LEVEL 1995 TO 1998.**

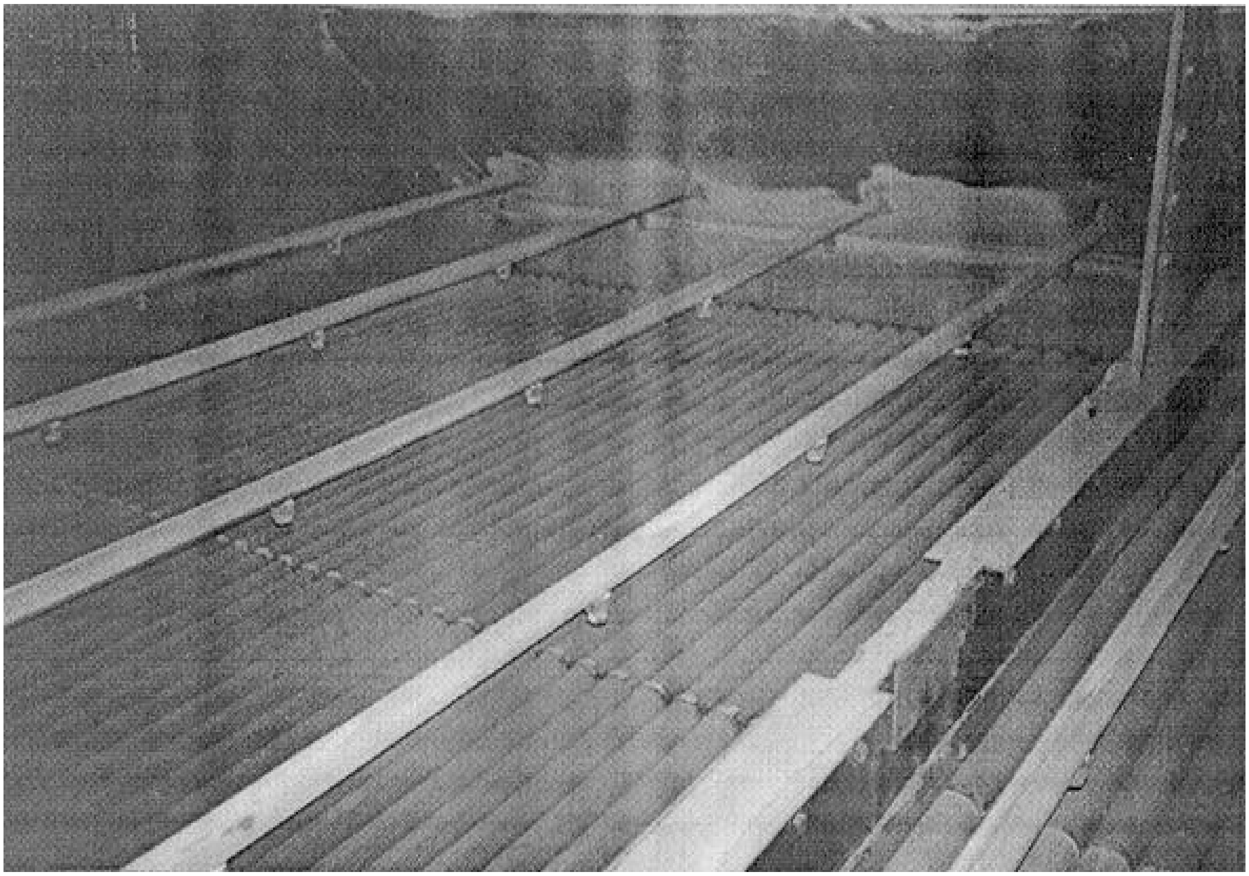


## WASH METHODS

Heat pipe cleaning is simplified through the use of internal wash pipes incorporated in the original design. Each air heater is equipped with 18 stationary wash pipes for off-line cleaning. The wash pipes each consume 180 gpm of water at 75 psig. Figure 4.11-11 shows the layout of the wash pipes above the top most heat pipe module. There are similar headers above each flue gas side module and each wash pipe is equipped with several nozzles.

When plant personnel first attempted to use the wash system, many nozzles were found to be plugged with fly ash deposits. Fly ash migration into the open nozzles during normal plant operation coupled with moisture and acid condensation caused the deposits. The problem is now avoided by operating the heat pipes with the nozzles removed and the nozzle connections capped: The nozzles are installed just before the heat pipes are to be washed. After washing, the nozzles are all removed and stored until needed again.

**FIGURE 4.11-10**
**WASH PIPES ABOVE TOP HEAT PIPE MODULE**



While the boiler is being taken off-line, the heat pipes are sootblown to remove as much fly ash and deposit material as possible. Washing of the heat pipes begins with the bottom module. The cold-end deposits are hard but are easily removed through a combination of deluge washing using the stationary wash headers and hand lancing. To facilitate the cleaning, the heat pipe high pressure air sootblowers are operated with the water sprays in service. This helps to loosen and break up deposits attached to the tubes and fins. After all modules have been cleaned by deluge washing, plant personnel inspect the modules. Cleanliness is determined by viewing, from the top side of a module, a light placed under the module. In this fashion the modules are inspected row by row.

Plugged areas are noted and manually cleaned by water jet using 1/4” tubing lances attached to fire hoses. With experience, heat pipe washing has become more routine. Plant personnel have reported that heat pipe washing originally took 7 days to complete and used more than 400,000 gallons of water. Currently, the heat pipes can be cleaned in *2.5-3* days with less than 200,000 gallons of water. The water usage is now similar to what is required for the Unit 1 Ljungstrom® units.

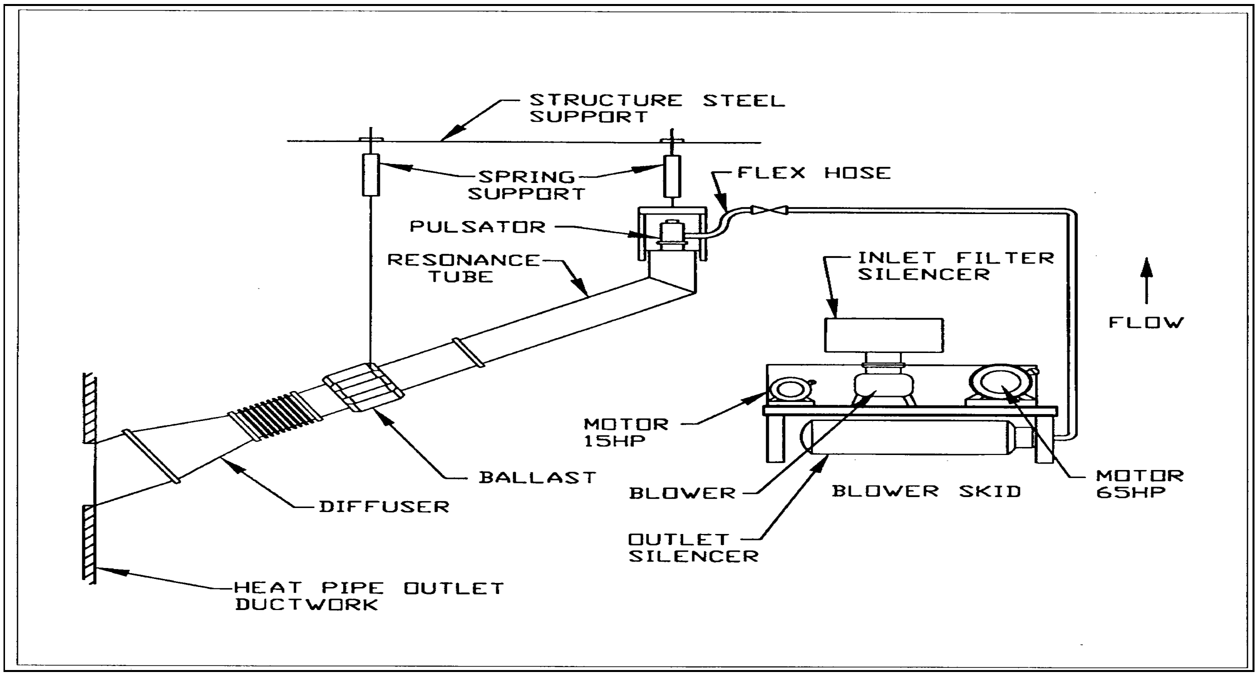
## INFRASONIC CLEANER TESTING

The original air sootblowers were not very effective in keeping the heat pipe cold-end tube modules free of deposits. Both the sequencing and frequency of sootblowing were changed without much success. To improve cleaning NYSEG decided to test the InfraSonik Infrafone® on the 2A heat pipe. This device uses high levels (up to 180 dB) of ultra low frequency (infrasonic) sound at 20Hz to remove and/or prevent deposit laid down on heat transfer surfaces. The technology is used in Europe, Japan, and the USA in both oil and coal fired services to clean boiler economizers and air heaters

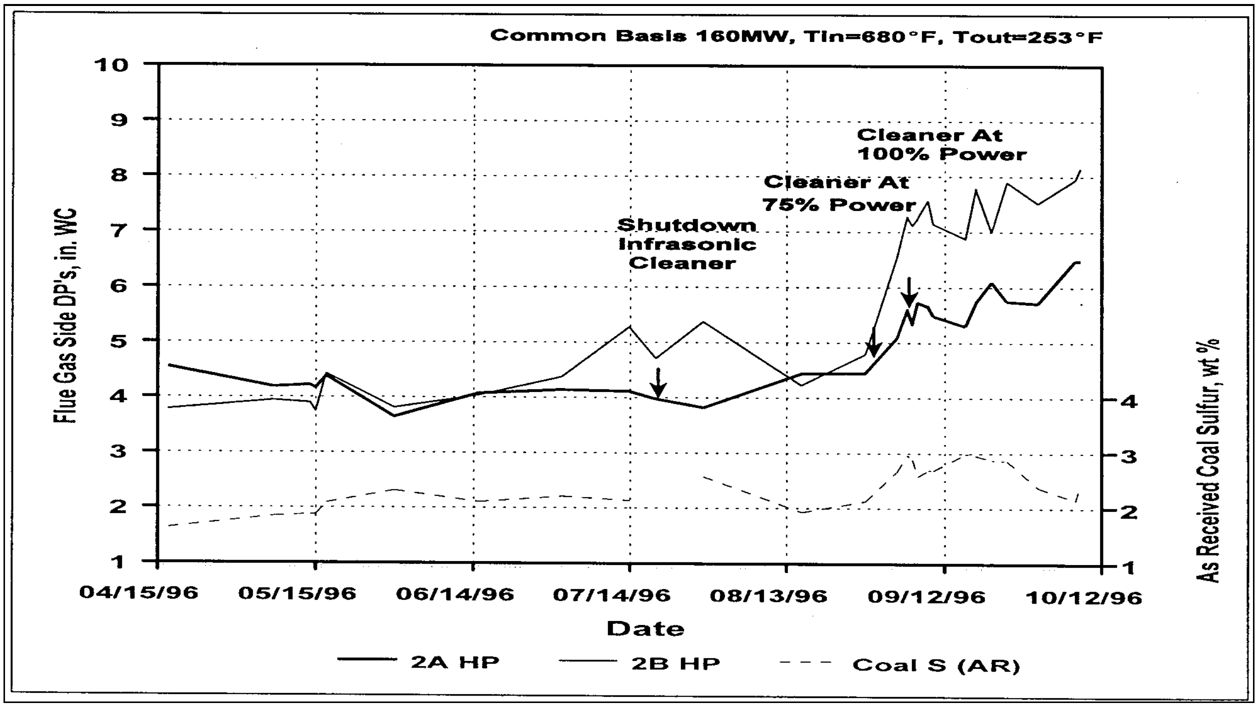
Figure 4.11-12 shows the general equipment configuration of the AP 5000 Infrafone® installation at Milliken. The installation consists of a low frequency sound generator (pulsator), a resonance tube, and a rotary lobe type blower package which supplies motive air to the pulsator. The pulsator and resonance tube combination is attached to a ductwork port just below the cold-end tube banks of the 2A heat pipe. At full power (5,000W acoustic) the blower supplies 1,059 scfm of air at about 13 psig. To achieve the highest cleaning benefit, the decision was made to operate the Infrafone® continuously rather than intermittently. Once the performance was established, the intent was to begin intermittent operation to establish the minimum required cleaning level.

Although initial operations of the infrasonic cleaner indicated reduced fouling in the 2A heat pipe, subsequent operations without the cleaner in service indicate that the effect was marginal for the Milliken installation. These conclusions are supported by figures 4.11-10 and -13 which show flue gas side pressure drops at high boiler load for both heat pipes. Since tube fouling restricts the gas flow in the heat pipes, the flue gas side pressure drops adjusted to a common basis can be used to follow fouling. Figure 4.11-13 shows the pressure drop behavior after the Infrafone® was first placed in service in early April 1996. Between April 17, 1996 to July 19, 1996, there is a slight decline in the 2A heat pipe pressure drop (4.5 in. WC dropping to 4.0 in. WC); indicating that the cleanliness of the 2A heat pipe was perhaps improving. At the same time, the common basis pressure drop for the 2B heat pipe increased from about 3.8 in. WC to 4.7 in. WC; indicating that the unit was experiencing increased fouling.

## FIGURE 4.11-11
## GENERAL LAYOUT OF INFRASONIC CLEANER SYSTEM



## FIGURE 4.11-12
## FLUE GAS SIDE PRESSURE DROPS AND COAL S DURING FIRST OPERATION OF INFRAFONE®



On July 19, 1996 the Infrafone® was shut down to allow repair of the ductwork between the 2A heat pipe and the particulate collector. Infrasonic resonance vibrations caused metal fatigue which produced cracks and holes in the ductwork. As shown in figure 4.11-13, while the Infrafone® was out of service, the 2A heat pipe pressure drop increased from 4.0 in. WC to 4.5 in. WC indicating increased fouling. However, for the same period, the 2B heat pipe pressure drop varied somewhat but overall remained essentially constant changing from 4.7 in. WC to 4.8 in. WC; indicating little or no significant fouling. When the Infrafone® was placed back in service at 75% power, the pressure drops across both heat pipes began to rapidly rise. The renewed operation of the Infrafone® may have suddenly loosen accumulated deposit and fly ash materials which then blocked flow channels as the materials traveled downward through the cold-end modules. Alternately, the change over of the plant fuel from a 1.8-2.2 wt % S to a 2.8-3.0 wt% coal may have increased acid deposition in the cold-end modules causing the pressure drop rise. Unlike early in the run, operating the Infrafone® at a 100 % power level did not again reduce the pressure drop across the 2A heat pipe. When Unit 2 was shut down in October 1996 after six months of operation, the cold-end fouling in both heat pipes was by visual inspection, essentially the same.

Figure 4.11-13 provides additional evidence that the use of the infrasonic cleaner did not significantly reduce heat pipe fouling. The figure shows the heat pipe pressure drops on a common basis and the as received coal sulfur levels from March 1995 to April 1998. The first two periods show the behavior before the infrasonic cleaner was installed. The third and fourth periods are plant operating periods when the infrasonic cleaner was operated. The last two periods are again with the infrasonic cleaner out of service. The fouling rates are relatively low for the first period (3/95 - 9/95) when coal sulfur levels were low at 1.8-2.1 wt % S and the heat pipe thermal performance was degraded, keeping cold-end temperatures high, due to gas generation in the naphthalene filled tubes. Between periods 1 and 2, repairs were made to the heat pipes to remove the non-condensable gases from the naphthalene tubes and the heat pipes were partially washed. The second period data shows that the partial washing was not adequate since fouling of both heat pipes was very rapid.

Between periods 2 and 3, the Infrafone® was installed and special care was taken in cleaning the heat pipes. During the first two periods, the 2A heat pipe fouled more quickly than the 2B unit. For periods 3 and 4 with the Infrafone® operating, the 2A heat pipe fouled somewhat more slowly than the 2B heat pipe indicating that the infrasonic cleaner provided some benefit. This, however, now appears to be an operational artifact since the 2A heat pipe also fouled more slowly during period *5* when the Infrafone® was not operated. For period 6, fouling rates appear to be about the same for both heat pipes. These results show that the Infrafone® was not able to significantly improve on-line cleaning above what was achieved with the air sootblowers.

The Infrafone® may work well in other utility boiler applications but its use does not appear to be of benefit in reducing heat pipe cold-end fouling. Because of the penetrating nature of low frequency sound and the high acoustic energy levels used, any application of this technology must address excitation and possible resonance vibrations in equipment and structures. At Milliken when the Infrafone® was operated, the concrete flooring below the Unit 2 precipitators vibrated enough that there was concern for failure due to a possible resonance situation. Structural dynamics and vibrations studies determined that the vibration caused by the Infrafone® was not detrimental to the structural integrity of the flooring. However, ductwork leading to the precipitators and the 2A heat pipe suffered damage caused by the intense low frequency sound. Figure 4.11-14 shows some of the metal cracking which occurred in the ductwork from the 2A heat pipe to the 2A precipitator. This vibration problem was cured by stiffening the ductwork. The ductwork (34' x 2.5' cross section) was internally stiffened using 4-inch diameter pipes welded at several levels across the 2.5' ductwork width. A total of 60 stiffening pipes were installed. Figures 4.11-15 and -16 show some of the cracking which developed in the primary flue gas/secondary flue gas division walls inside the 2A heat pipe. Figure 4.11-17 shows how sideways vibration of a finned tube caused *5/8"* deep slots to be cut into a gas diversion plate in the 2A heat pipe cold-end module. After the internal damage was discovered, the decision was made to cease further operation of the infrasonic cleaner.

**FIGURE 4.11-13**
**VIBRATION DAMAGED DUCT BETWEEN THE 2A HEAT PIPE OUTLET AND THE PRECIPITATOR INLET**

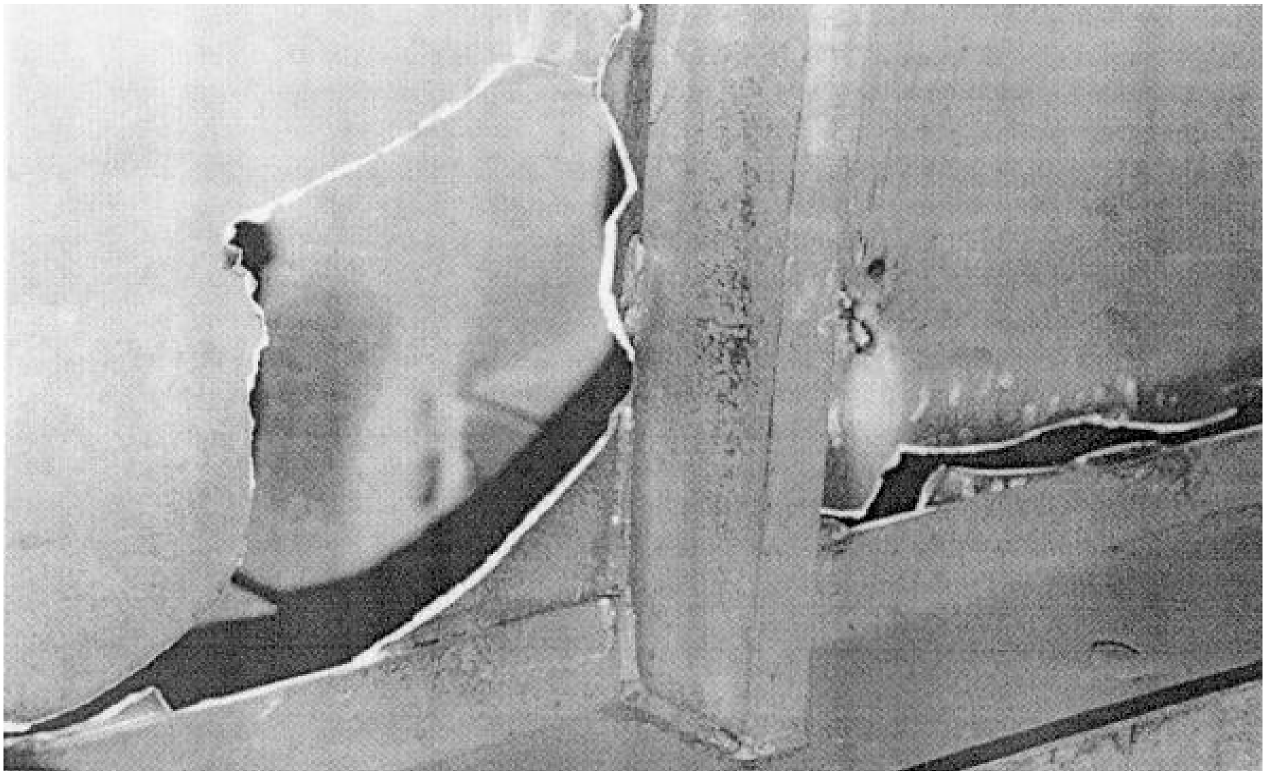


FIGURE 4.11-14
VIBRATION-CAUSED WALL CRACKING IN THE 2A HEAT PIPE AT AN INTERNAL SOOTBLOWER LANCE PORT

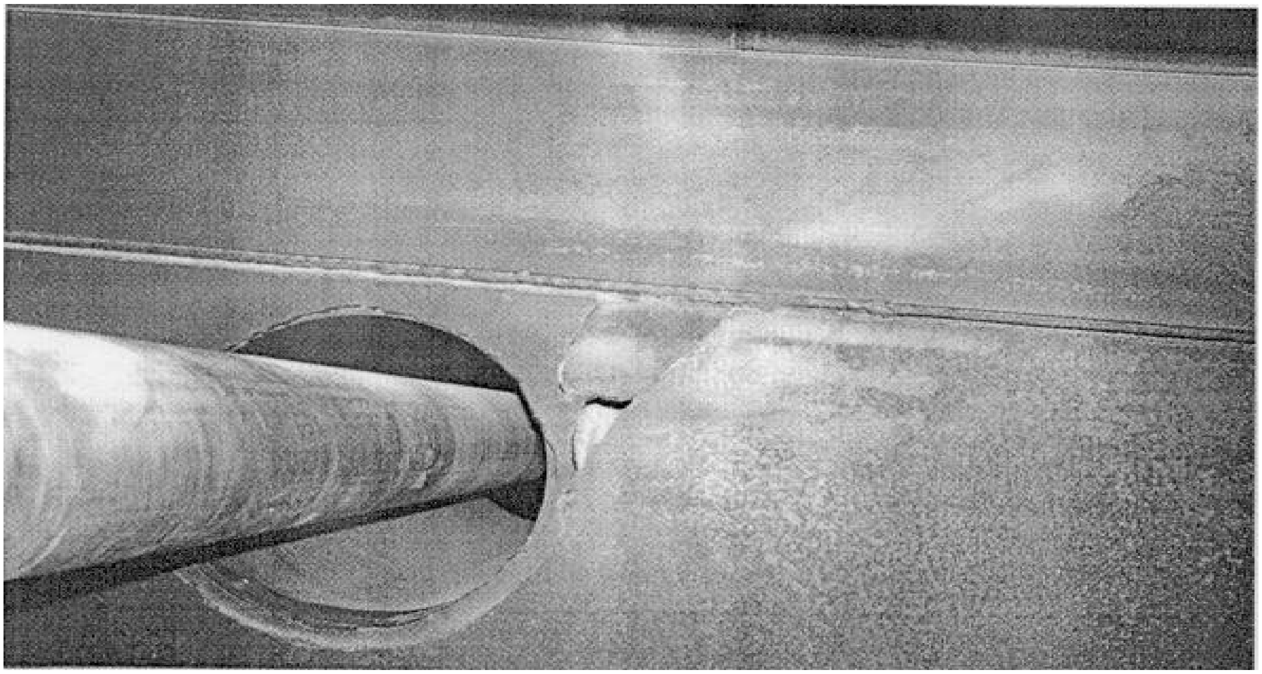


FIGURE 4.11-15
REPAIRED CRACKS IN THE PRIMARY/SECONDARY
FLUE GAS DIVISION WALL OF THE 2A HEAT PIPE

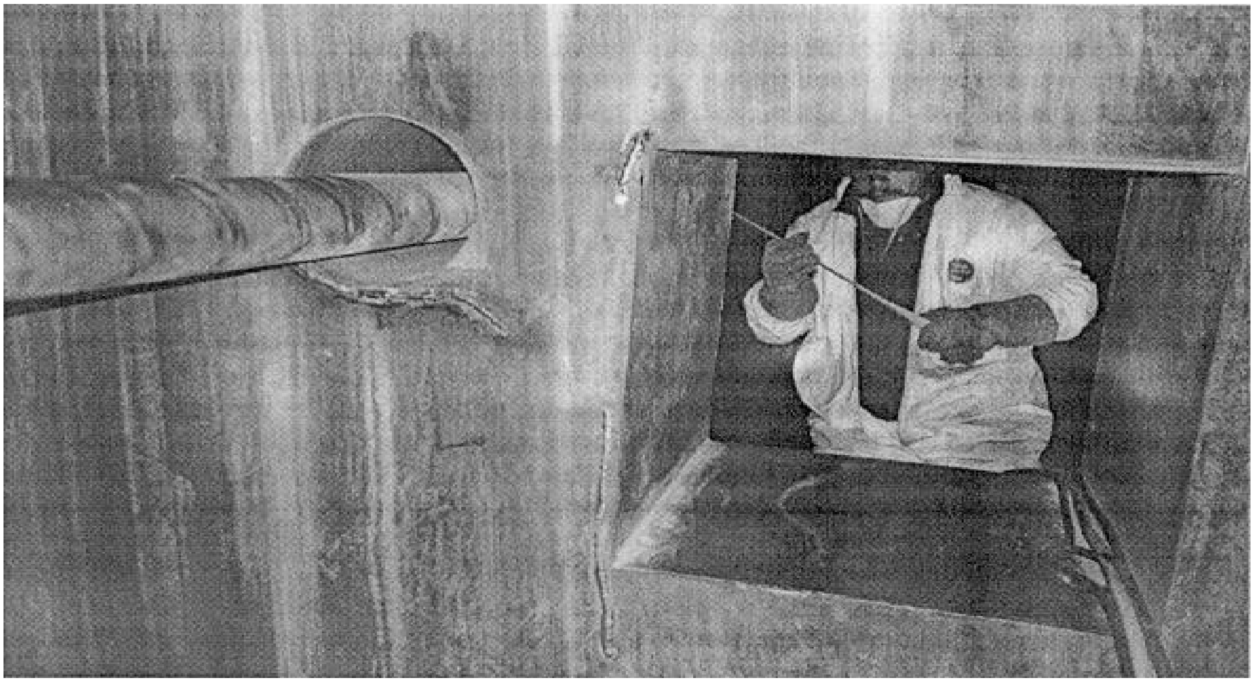
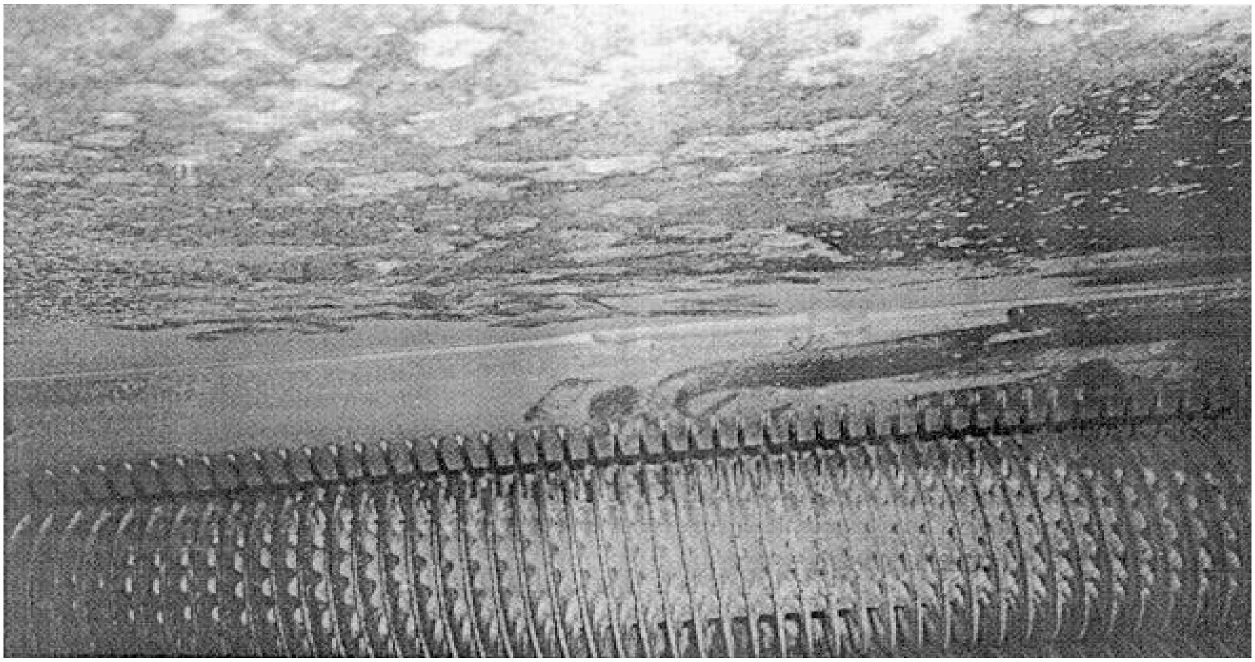


FIGURE 4.11-16
SLOTS CUT INTO GAS DIVERSION PLATE DUE TO VIBRATION OF FINNED TUBES IN 2A HEAT PIPE



### SOOTBLOWER MODIFICATIONS

To compare the Infrafone® operation with improved sootblowing, modifications were made to the row of sootblower lances located above the cold-end module of the 2B heat pipe. The standard 1/2" diameter Bergamann cone nozzles were replaced with special 5/8" diameter diverging venturi nozzles (CFE nozzles) on four lances. This allowed the peak impact pressure at the heat pipes to be increased without consuming additional air.

The performance of the Infrafone® against the modified sootblowers was discussed in the previous section. Since the Infrafone® was not operated during the last two plant operating periods (see figure 4.11-13), a performance comparison can be made between the originally installed sootblowing lances in the 2A heat pipe and the modified lances in the 2B heat pipe. The heat pipe pressure drop data shown in figure 4.11-13 do not indicate any significant benefit of using the CFE nozzles. Towards the end of the fifth operating period, the 2B heat pipe pressure drop actually rose more rapidly than for the 2A heat pipe; indicating possible poorer performance. However, for the sixth operating period, the level of cleaning appears to be about the same for both heat pipes. These results do not show improved cleaning performance for the Milliken application of the CFE nozzles.

## 4.11.6 HEAT PIPE AIR HEATER PERFORMANCE BENEFITS

### THERMAL PERFORMANCE COMPARISON WITH ROTARY AIR HEATER

Originally the Milliken Units 1 and 2 were both equipped with rotary (Ljungstrom®) air heaters. For the Milliken CCT-IV program, only the Unit 2 Ljungstroms® were replaced with heat pipe air heaters. Since Milliken Units 1 and 2 are essentially identical units with identical capacities, conducting simultaneous detailed performance tests would be an ideal means comparing the performance of the two air heater system designs. However, this was not part of the Milliken test program. It would have doubled the detailed testing costs and would have required installation of many new test ports around the Unit 1 air heaters. Additionally, problems with re-basketing the Unit 1 air heaters resulted in somewhat higher flue gas outlet temperatures. Therefore, the thermal performance comparison would be against a slightly degraded Ljungstrom® air heater system.

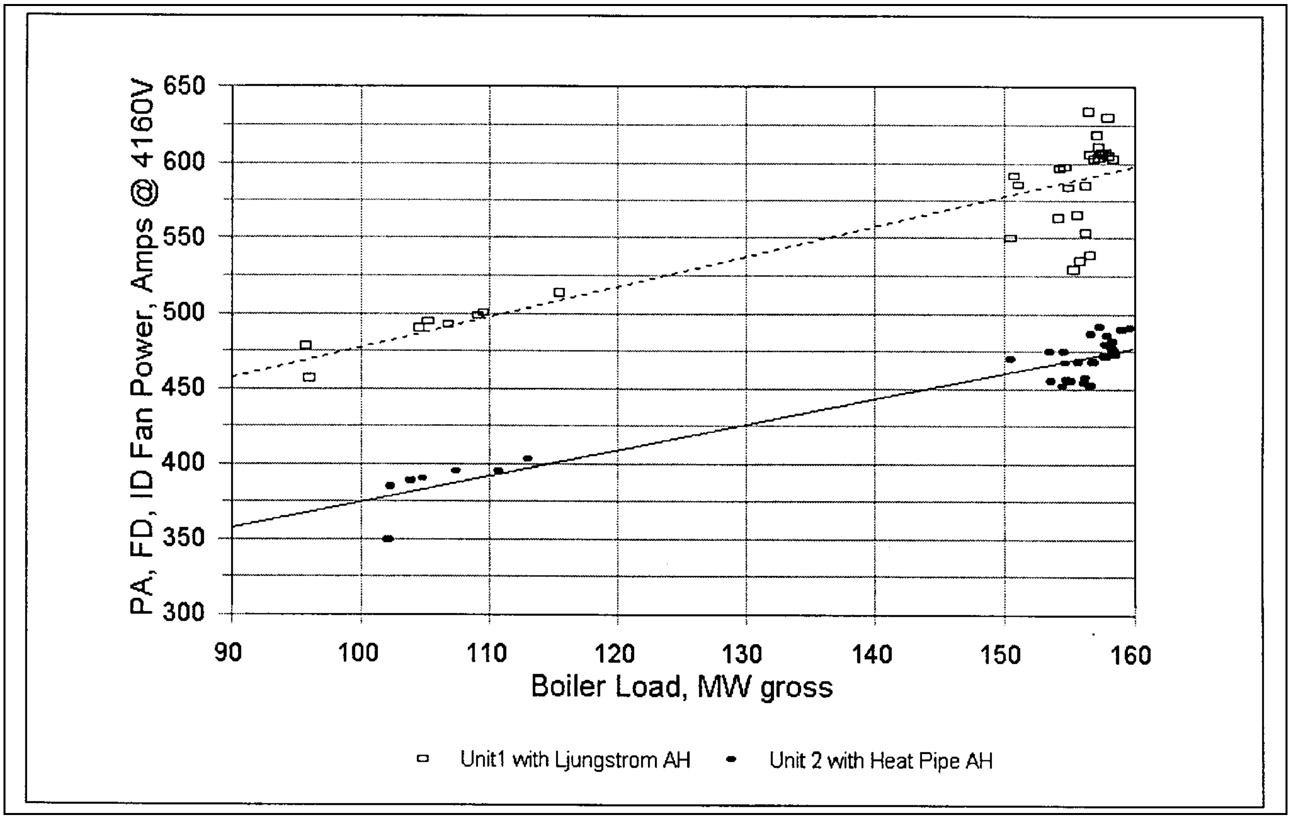
To compare the heat pipe air heater thermal performance against the original Ljungstrom® system, data for ESP performance tests conducted in 1994~ were used. The ESP data included coal analyses, and ESP inlet (air heater outlet) flue gas compositions and temperatures. The data did not include air heater inlet gas compositions and temperatures, so the total heat recovery in the air heaters could not be determined for the comparison. However, the data were sufficient to calculate the flue gas heat losses to the stack based on the ESP inlet conditions using the method shown in "Steam/Its Generation And Use." Assuming similar air heater inlet conditions, lower heat losses to the stack indicate improved thermal performance. Table 4.11-7 summarizes the stack heat losses. The detailed calculations can be found in Appendix H of the Heat Pipe Final Report. The results indicate, that in a clean condition, the new heat pipe air heaters are just as thermally effective as the original Ljungstrom® units. Both air heater systems lose as sensible heat about 9.9% of the energy contained in the fuel with the flue gases flowing to the FGD or stack.

## AIR LEAK REDUCTION BENEFITS

The results presented in table 4.11-7 also show that the excess air levels at the outlet of the Ljungstrom® units were typically 12% to 24% higher than for the heat pipes. The higher excess air levels are due to air side-to-flue gas side leakage within the Ljungstrom® air heaters. The leakage increases the power requirements for the primary air, secondary air, and induced draft (ID) fans and can result in more pumps being placed in service in the FGD. For Units I and 2, typical fan power data obtained at approximately one-month intervals between November 1996 and February 1998 are shown in figure 4.11-18. The data are for stable operating periods when units 1 and 2 were operated together at approximately the same boiler loads with the economizer exit oxygens at similar levels (see table 4.11-8).

Figure 4.11-18 shows that the Unit 1 fan amperages are significantly higher than the Unit 2 amperages under both low and high boiler load conditions. The differences are approximately 103 amps and 120 amps at boiler gross loads of 100 MW and 160 MW, respectively. Assuming a 0.90 power factor (PF) for the fan motors, the amperage differences are equivalent to 0.67 MW for the 100MW gross load operation and 0.78 MW for the 160 MW gross load operation. These differences represent 0.67% and 0.49% of the low and high load gross power generations, respectively. The results indicate that the use of zero air leak designs, such as provided by the heat pipe air heaters, can provide small but significant performance improvements which can reduce power generation costs.

**FIGURE 4.11-17**
**FAN POWER REQUIREMENTS FOR MILLIKEN UNITS 1 & 2**



## TABLE 4.11-7

## STACK HEAT LOSS COMPARISON FOR LJUNGSTROM® AND HEAT PIPE AIR HEATERS MILLIKEN UNIT 2 -- FULL BOILER LOAD OPERATIONS

|  |  |  |  |  |  |  |
|---|---|---|---|---|---|---|
| Air Heater Type | Ljungstrom® |  |  |  |  |  |
| Date | 4/18/94 | 4/19/94 | 4/20/94 |  |  |  |
| Flue Gas Temp, $^0$F | 264 | 266 | 258 |  |  |  |
| Composition, mol % |  |  |  |  |  |  |
| $O_2$ | 7.0 | 7.1 | 7.1 |  |  |  |
| $CO_2$ | 12.5 | 12.4 | 12.4 |  |  |  |
| $N_2$ | 80.5 | 80.5 | 80.5 |  |  |  |
| % Excess Air | 49 | 50 | 50 |  |  |  |
| Stack Heat Loss (1) | 9.90 | 9.77 | 10.9 |  |  |  |
|  |  |  |  |  |  |  |
| **Avg. Heat Loss to Stack** |  | **9.92** |  |  |  |  |
|  |  |  |  |  |  |  |
| **Air Heater Type** | **Heat Pipe** |  |  |  |  |  |
| Date | 10/17/95 | 10/18/95 | 5/14/96 | 5/15/96 | 11/7/96 | 11/8/96 |
| Flue Gas Temp, $^0$F | 289 | 294 | 288 | 290 | 292 | 281 |
| Composition, mol % |  |  |  |  |  |  |
| $O_2$ | 5.8 | 5.8 | 4.4 | 4.6 | 4.6 | 4.9 |
| $CO_2$ | 13.3 | 13.2 | 14.5 | 14.3 | 14.3 | 14.0 |
| $N_2$ | 81.0 | 81.0 | 81.2 | 81.2 | 81.1 | 81.1 |
| % Excess Air | 37 | 37 | 26 | 27 | 27 | 30 |
| Stack Heat Loss (1) | 10.07 | 10.16 | 9.64 | 9.81 | 9.86 | 10.05 |
|  |  |  |  |  |  |  |
| Avg. Heat Loss to Stack |  |  | 9.93 |  |  |  |
|  |  |  |  |  |  |  |
| (1) Percent of Fuel Energy |  |  |  |  |  |  |

# TABLE 4.11-8
# PERFORMANCE SUMMARY FOR UNITS 1 & 2

| Date M/D/Y | Time Hr:Min | MW Gross | | Economizer O2 | | Fan Currents, Amps (1) | | |
|---|---|---|---|---|---|---|---|---|
| | | Unit 1 | Unit 2 | Unit 1 | Unit 2 | Unit 1 | Unit 2 | Diff (2) |
| 11/8/96 | 06:00 - 08:00 | 151.1 | 158.4 | (3) | 3.2 | *585.9* | 475.6 | -110.3 |
| 11/8/96 | 08:00 - 12:00 | 157.5 | 158.5 | (3) | 3.2 | **606.6** | 472.5 | -134.1 |
| 11/8/96 | 12:00 - 16:00 | 154.2 | 157.7 | (3) | 3.2 | *596.6* | 471.9 | -124.7 |
| 1/9/97 | 10:00 - 12:30 | 154.7 | 158.3 | 3.3 | 3.3 | 597.8 | 477.0 | -120.8 |
| 1/9/97 | 16:00 - 20:30 | 156.6 | 157.8 | 3.3 | 3.4 | **606.3** | **479.4** | -127.0 |
| 2/11/97 | 08:00 - 12:00 | 157.5 | 159.7 | 3.3 | 3.3 | **605.7** | 490.5 | -115.2 |
| 2/11/97 | 12:00- 15:00 | 157.8 | 159.1 | 3.3 | 3.3 | **607.3** | 489.6 | -117.6 |
| 2/11/97 | 20:00 - 23:00 | 104.5 | 103.9 | 4.5 | 4.5 | 490.2 | 388.3 | -101.9 |
| 3/1/97 | 03:00 - 05:00 | 157.3 | 157.4 | 3.3 | 3.3 | 610.9 | 491.7 | -119.2 |
| 3/1/97 | 07:00 - 13:00 | 150.8 | 150.6 | 3.4 | 3.4 | *591.7* | 470.1 | -121.7 |
| 3/1/97 | 14:00 - 24:00 | 109.0 | 107.5 | 4.4 | 4.5 | 498.8 | 394.8 | -104.0 |
| 4/22/97 | 00:00 - 05:00 | 105.1 | 102.2 | 4.9 | 4.8 | 494.9 | 384.4 | -110.5 |
| 4/22/97 | 07:00 - 14:00 | 157.2 | 156.8 | 3.6 | 3.3 | 618.6 | 467.7 | -151.0 |
| 4/22/97 | 20:00 - 21:00 | 150.5 | 153.6 | 3.4 | 3.3 | 550.6 | 455.2 | *-95.4* |
| 5/3/97 | 04.00 - 07:00 | 115.5 | 113.0 | 4.2 | 4.6 | 514.1 | 402.8 | -111.3 |
| 5/3/97 | 08:00 - 12:00 | 156.5 | 154.6 | 3.3 | 3.3 | 634.5 | 474.5 | *-159.9* |
| 5/3/97 | 19:00 - 21:00 | 109.5 | 110.8 | 4.4 | 4.4 | 500.5 | 394.8 | -105.8 |
| 6/2/97 | 14:00 - 18:00 | 154.1 | 154.8 | 2.9 | 3.3 | 563.5 | 467.5 | -96.0 |
| 6/2/97 | 18:00 - 21:00 | 156.2 | 155.7 | 3.4 | 3.3 | 585.8 | 467.9 | -117.9 |
| 7/1/97 | 01:30 - 04:30 | *95.9* | 102.1 | 5.3 | 4.8 | **457.2** | 349.7 | -107.5 |
| 8/1/97 | 00:00 - 05:30 | 106.7 | 104.8 | 4.2 | 4.6 | **492.7** | 390.0 | -102.7 |
| 8/1/97 | 10:00 - 16:00 | 157.3 | 157.9 | 3.1 | 3.3 | 604.2 | 485.3 | -119.0 |
| 8/1/97 | 19:00 - 22:00 | 156.9 | 157.9 | 3.0 | 3.3 | 602.8 | 471.6 | -131.3 |
| 9/4/97 | 11:00 - 16:00 | 158.4 | 156.7 | 3.4 | 3.3 | **603.2** | 486.3 | -116.9 |
| 9/30/97 | 12:00 - 13:30 | Off Line | 153.5 | Off | 2.9 | Off Line | **474.6** | |
| 11/5/97 | 08:00 - 18:00 | 156.5 | 158.0 | 3.3 | 3.3 | 598.2 | 483.1 | -115.2 |
| 12/2/97 | 08:00 - 16:00 | 157.9 | 158.4 | 3.3 | 3.3 | **630.6** | 476.2 | **-154.4** |
| 1/30/98 | 06:00 - 08:00 | 154.9 | 156.3 | 3.4 | 3.0 | 583.9 | 457.5 | -126.4 |
| 1/30/98 | 08:00 - 12:00 | 155.6 | 156.1 | 3.3 | 3.0 | *565.5* | 454.4 | -111.2 |
| 1/30/98 | 12:00 - 16:00 | 156.2 | 156.6 | 3.3 | 3.0 | **554.2** | 452.5 | -101.7 |
| 2/16/98 | 0 1:00 - 03:00 | 156.5 | 155.1 | 3.1 | 3.2 | 539.1 | **455.0** | -84.1 |
| 2/16/98 | 04:00 - 06:00 | 155.8 | 154.8 | 3.1 | 3.3 | 535.0 | 456.2 | -78.8 |
| 2/16/98 | 18:00 - 20:00 | 155.3 | 154.5 | 3.1 | 3.2 | 529.2 | 451.7 | -77.5 |

1) For Primary Air, Forced Draft and Induced Draft Fan Amps at 41 60V.
2) Unit 2 - Unit 1 value.
3) Problem With Analyzer Signal.

## 4.11.7 CONCLUSIONS AND RECOMMENDATIONS

### 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, $SO_2$ and NOx 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 $^0$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 $^0$F-18 $^0$F above the 253 $^0$F design temperature and for the 2B heat pipe was 12 $^0$F above the design. For the November 1996 performance tests, the differences were slightly higher at 20 $^0$F-23 $^0$F for the 2A heat pipe and 15 $^0$F - 16 $^0$F for the 2B heat pipe. Based on an analysis done by CONSOL R&D, the uncertainty in these results is ±4.4 $^0$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 $^0$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 (900 hp) 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 Infrafone® 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 Infrafone® is a device which uses high intensity, ultra low frequency sound for on-line equipment cleaning. Neither the Infrafone® nor the modified sootblower lances appeared to provide any significant cold-end cleaning benefit over the existing sootblowers. The Infrafone® 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 $SO_3$ level to the heat pipe air heaters by injecting additives such as $Mg(OH)_2$ or MgO into the boiler. Reducing the flue gas $SO_3$ level would decrease the acid dew point and allow lower temperature operation without condensation. This form of $SO_3$ 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.

## 4.12 MILLIKEN MATERIALS OF CONSTRUCTION

As part of the implementation of the demonstration portion of the Milliken Clean Coal Technology Demonstration Project, NYSEG identified the Milliken Materials of Construction project. This 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. The results of this program were compiled in a report authored by CONSOL, Inc., entitled “Evaluation of Materials of Construction Used In the U.S. DOE Clean Coal IV Project at the New York State Electric and Gas Company Milliken Station”. This report includes a review of boiler water wall tube wastage (due to installation of low- $NO_X$ burners), post-boiler corrosion, absorber construction, and miscellaneous absorber equipment. The CONSOL report is available upon request from NYSEG. A summary of the report is presented below.

### 4.12.1 SUMMARY OF KEY FINDINGS

The materials of construction were examined as part of the evaluation of emission reduction and efficiency improvement technologies at Milliken Station. Key findings are as follows:

- During the first two years of low-$NO_X$ 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.
- The flakeglass coating was not properly applied to the carbon steel transition section between the absorber exit and the stack, causing isolated corrosion spots. 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.

### 4.12.2 LOW-NO$_X$ BURNERS - BOILER WATER WALL TUBE WASTAGE

The burners and control systems were modified at NYSEG's expense to reduce NO$_X$ emissions. NYSEG selected ABB C-E's third generation Low-NO$_X$ Concentric Firing System (LNCFS-III) burners coupled with Staged Overfire Air (SOFA). NYSEG engineers redesigned the pulverized coal system to provide finer coal particles for more complete carbon burnout.

A recent problem emerging at plants using low-NO$_X$ burners is accelerated water-wall tube wastage due to fireside corrosion and erosion. The fuel rich combustion zone created by low-NO$_X$ operating conditions contains a reducing gas that is more corrosive than the combustion gas produced with non low-NO$_X$ burners. Flame impingement and slag accumulation on the waterwall tubing during low-NO$_X$ firing can lead to erosion or corrosion of the tubes. ABB CE's LNCFS Ill burners are designed to minimize corrosion and erosion by yawing the auxiliary air nozzles toward the waterwall tubing to make the gas zone near the waterwall tubes more oxidizing and, thus, less corrosive. The auxiliary air yaw angle provides a protective blanket of clean gas near the tubes to minimize flame impingement and slag accumulation.

Before the modifications, the waterwall tubing at Milliken Station traditionally required only minor maintenance, such as weld overlay and selective tube replacement, mostly due to sootblower erosion. Maintenance records do not indicate any remedial maintenance for fireside corrosion, or tube failures due to fireside corrosion, prior to installation of the low-$NO_X$ burners.

To determine the effect of the LNCFS Ill burners on waterwall tube wastage, three separate ultrasonic tube thickness surveys of the Unit I waterwall tubes were performed in 1985, 1993, and l995. The 1993 measurements were compared to the 1985 measurements to determine the baseline wastage rate prior to the low-$NO_X$ burner retrofit of Unit 1 in June 1993. The 1995 measurements were compared with the 1993 measurements to determine the post-retrofit wastage rate. The results of these tests are summarized below.. The details of the methods and results are reported in "A Study of LNCFS Ill Coal Burners on Boiler Waterwall Tube Wastage," NYSEG Report to the Department of Energy, December 13, 1995.

The baseline wastage rates were less than 5 mils per year (mpy) at more than 99.4% of the nearly 8,000 test locations. The highest wastage rate was 35 mpy in an area where sootblower erosion is expected. The baseline wastage rate required no substantial remedial action.

The post-retrofit measurements (after 16,760 hours of low-$NO_X$ operation) indicated that the waterwall tube wastage rate in some areas of the boiler increased substantially. Only 75% of the test locations showed wastage rates of less than 7 mpy. Above the burners and below the boiler sootblowers, the area most likely to experience corrosion, nearly 400 locations (about 5% of the total test locations) were found where the wastage rate was greater than 8 mpy; more than half of these locations were wasting at more than 13 mpy. The average wastage rate for these locations was 16 mpy. NYSEG estimates that the remaining life for tubing experiencing this wastage rate is about 13 years. The highest wastage rate for tubes in this area was 103 mpy, giving an estimated remaining life of two years; the second highest wastage rate was 50 mpy. In the sootblower erosion area, 76 of the test locations had a wastage rate greater than 15 mpy. The highest wastage rate in the sootblower erosion area was 103 mpy; the second highest was 59 mpy.

After the 1995 survey, no remedial actions were taken, but it was recommended that ultrasonic tube thickness testing be included in annual boiler maintenance inspections. Such an inspection was performed on the north (right) boiler wall during a short maintenance outage in 1996. These tests revealed a much lower tube wastage rate.

The north wall average tube wastage for 1995-96 was 3 mpy, compared to 17 mpy for 1993-95. The difference was attributed by NYSEG to measurement errors and unspecified changes in boiler operation.

### 4.12.3 POST-BOILER CORROSION MONITORING

Prior to the absorber installation, Milliken burned coal containing approx. 1.5% S. After the retrofit wet absorber for $SO_2$ control was installed in 1995, Milliken Station burned coal with a higher sulfur content, resulting in a higher flue gas acid dew point. This, coupled with the lower flue gas temperature resulting from the heat pipe air heater system, could accelerate corrosion in the ductwork upstream of the absorber. A Mentor I (formerly known as CAPCIS) corrosion monitoring system was included in the demonstration project. The corrosion monitoring system includes electrochemical probes, monitoring equipment, and diagnostic software. The probes are installed in the flue gas stream; they measure electrochemical impedance, electrochemical potential noise, electrochemical current noise, and temperature. This combination of measurements is sensitive to changes in the rate of corrosion. Diagnostic software analyzes the sensor data to determine the type of corrosion and the relative corrosion rate and severity. The software was upgraded in December 1995 to improve trouble shooting and data capture. Temperature sensing problems were corrected in December 1995. Problems were encountered when downloading the historical data from the Mentor 1 system; these have not been resolved yet.

Problems with the heat pipe in 1995 resulted in high flue gas temperatures and, thus, low corrosion rates. The Mentor 1 probes and the duct walls were inspected in April 1997. The diameters of the probes were measured to determine the overall corrosion rates and the duct wall thicknesses were measured at several locations between the ID fan discharge and the SHU absorber inlet. The corrosion probe data indicated that there was no measurable corrosion of the Cor-Ten® A material and only 3 to 5 mpy wastage for the SA-178A carbon steel.

### 4.12.4 FGD ABSORBERS

#### SHU ABSORBER CONSTRUCTION

The SHU process is the only developed limestone wet FGD process that is specifically designed to employ the benefits of low-pH operation, formic acid enhancement, single loop, cocurrent/countercurrent absorption and in-situ forced oxidation. The absorber does not include any packing or grid work; this significantly reduces the potential for plugging and reduces the energy consumption of the boiler ID fans. The innovative formic acid-enhanced SHU process design has operated successfully in European generating stations since 1983.

At Milliken Station, the absorber and related equipment are located beneath a new chimney. This design approach saves considerable site space which is a benefit at existing plants where space to retrofit an FGD is at a premium. An additional feature demonstrated for the FGD market is the use of a tile-lined, split module absorber. The split module allows the flue gas from each boiler to be independently treated at a lower capital cost than would be required for the construction of two separate vessels.

### Stebbins Tile Lining and Grout

The SEMPLATE® ceramic tile lining, provided by Stebbins Engineering and Manufacturing Company of Watertown, NY, is a pressed fireclay brick with a chemical-resistant salt glaze. It is more abrasion and corrosion resistant than rubber and alloy linings, and is expected to last the life of the plant. The mortar is expected to be very reliable, needing only periodic inspection and repointing about every ten years. Lifecycle costs are expected to be lower than those of either a steel alloy absorber or a carbon steel absorber lined with chlorobutyl rubber or flakeglass. The Stebbins tile and mortar system is used with high success in the chemical process industry in harsher chemical environments than found in an FGD system.

The exterior walls of the absorber were constructed of various thicknesses of carbon steel reinforced concrete walls with insulating block exterior, SEMPLATE® interior and SEMPLATE® coping at top. All interior joints were fully grouted with AR-196 mortar cement, a chemically-resistant, silica-filled, vinyl ester. Carbon steel reinforced concrete/SEMPLATE® support corbels were provided for support of spray piping and mist eliminators. The floors of the split module were constructed of carbon steel reinforced concrete floor fill. A two-inch grouted SEMPLATE® lining was installed over the floor fill. Piping penetrations were constructed of flanged Hastelloy nozzles set in the structural wall with fiberglass reinforced plastic inserts set solidly in AR-196 mortar cement. Penetrations for the quench spray piping were Hastelloy C-22 nozzles set solidly in the structural wall. Penetrations for access doors were constructed of flanged carbon steel set in the structural wall with fiberglass reinforced plastic (FRP) inserts set solidly in AR-196 mortar cement. Carbon steel blinds for the access doors were provided with rubber gaskets to protect them from interior corrosion. Embedded Hastelloy C-22 alloy bolting was provided for attachment of turning vanes, and alloy embed plates were provided on the interior walls of each split module to accommodate attachments for catwalks, pipe supports, ladders, etc. A video was made to document the construction of the tile-lined absorber module.

## ABSORBER INSPECTIONS

The absorbers were brought on line in January 1995 (Unit 2) and June 1995 (Unit 1). The absorbers were inspected in March/April 1996, March/April 1997, and September/October 1997. No significant deterioration of the Stebbins tile or grout was observed in the inspections. No substantial cracks were observed in the walls or floors of the absorbers. Deposits of scale on the walls and an accumulation of solids on the floor were observed in both absorber modules. The deposits were mainly gypsum with some silica, alumina and iron. NYSEG's absorber inspection reports are included in Appendix B of the Materials of Construction report. Summaries of the inspections follow.

**March/April 1996 Units 1 and 2 absorber inspections**—A very large pile of solids was observed on the floor in both absorbers. In Unit 2, the pile sloped from a height of eight feet at the west wall to zero near the agitators at the east wall (figure 4.12-1). The suction lines for recirculation pumps A and E were partially restricted by the pile. The solids pile on the floor in the Unit 1 absorber was about half the size of the Unit 2 pile. Wall scale deposits in both units varied in thickness from 0.5 to 1.5 inches. After drying, the wall scale flaked off and was easily removed from the wall using a fire hose spray. There was no visible damage to the wall and floor tiles after the wall scale and floor deposits were removed. Deposits were found inside the oxidation air pipes, about 1.5 ft from the pipe exit, restricting about half of the pipe cross-sectional areas.

Samples of the floor, wall and air pipe deposits were taken during the inspection of the Unit 1 absorber. Samples of the gypsum product, ESP ash, and the feed limestone were taken at the same time for comparison. The analyses, shown in table 4.12-1, indicate the deposits were mostly gypsum with smaller amounts of iron, alumina and silica.

**March/April 1997 Unit 2 absorber inspection**—Scale on the absorber walls was approximately 0.5 inches thick; it was easily removed using a fire hose spray. The pile of solids on the absorber floor was not as deep as observed during the 1996 inspection. Pieces of rubber from the turning vanes were found in the floor deposits. No samples were taken during this inspection.

**September/October 1997 Units 1 and 2 absorber inspections**—In Unit 1, the pile of floor deposits sloped from a height of six feet at the east wall to zero near the center of the absorber floor. The solids pile on the floor in the Unit 2 absorber sloped from a height of seven feet at the west wall to zero near the center of the floor. Wall scale deposits were 0.5 to 2 inches thick in Unit 1 and 0.5 to 1 inch thick in Unit 2. The wall deposits below the water line were tan and soft and easily removed from the wall using a fire hose spray. The wall deposits above the water line were black and hard and had to be removed with a metal scraper. The Stebbins tiles in the lower absorber region were in excellent shape with no visible cracks. A few cracks were found in the first row of Stebbins tiles at the top of the absorber; the cracks may have been caused by load stress from the transition structure above the tiles, because some of the cracks continued down into the second and third row of tiles.

The upper portion of the cocurrent (gas inlet) side of the SHU absorber is lined with pressed fireclay acid brick. The bricks are made from the same material as the absorber wall tile, but with no salt glaze. Although there was no consistent wear pattern in any general area, wear and erosion was observed on some isolated individual bricks during the 1997 absorber inspections; this was worse in Unit 1 than in Unit 2. Because the wear pattern was not uniform, it is likely that the worn bricks came from a bad lot. The wear did not warrant replacement of the bricks.

### 4.12.5 MISCELLANEOUS ABSORBER EQUIPMENT

#### ABSORBER RECIRCULATION PUMPS

Absorber recycle pump linings at limestone wet FGD installations are usually rubber and they are typically replaced every two years. The original rubber suction liners on most of the recirculation pumps at Milliken Station degraded after eight months of operation; the only exceptions were Unit l's E pump and Unit 2's F pump. The liners on all but these two pumps were replaced with polyurethane in 1996. As of the 1997 outages, the polyurethane liners were inspected and were in good condition.

#### ABSORBER AGITATORS

There are five absorber agitators near the bottom of each absorber. The agitators were inspected in 1997. Scattered pitting on the back of the impellers was observed on all of the agitators in both units. All of the absorber agitator blades had heavily pitted regions or void spots. A hairline crack 1" long was observed on the front of agitator A's impeller blade; no cracks were found on agitators B, C, D or E. In the Unit 2 absorber, hairline cracks 3-5" long were observed on the impeller blades of agitators A, B, and D; the agitator manufacturer replaced these three blades at no charge. Corrosion or erosion is assumed to be the likely cause of the observed pitting. A copy of the inspection reports is included in Appendix C of the Materials of Construction report.

#### MIST ELIMINATOR

Mist eliminators in FGD units are particularly susceptible to scaling by calcium sulfate. However, this has not been a problem at Milliken Station. Make-up water is used for washing the mist eliminators in the SHU process. Visual inspections during scheduled outages in April 1996, April 1997 and September/October 1997 revealed that the mist eliminators on Unit I and Unit 2 were free of substantial deposits. Deposits were less than one-eighth inch thick, except in the corners where the wash sprays did not reach. There were no obvious signs of mist eliminator degradation or missing pieces. A sample of the mist eliminator deposit, collected during the 1996 inspection, indicates that the deposit was mostly gypsum with smaller amounts of iron, alumina and silica (table 4.12-1).

#### HYDROCYCLONES

The hydrocyclones were inspected in 1997 and found to be in good working order with no substantial wear or scale buildup on the internal walls.

#### FLAKEGLASS COATINGS

Some process tanks are lined with flakeglass coating, as is the carbon steel transition section between the absorber exit and the stack. During an inspection of the transition section in March 1996, corrosion was noted at the lifting lugs and around the entry doors. The corroded areas were touched up with high temperature epoxy and no subsequent corrosion has been observed. The flakeglass-lined tanks were inspected in March/April 1997 and were in good condition with no observable corrosion.

## FRP STACK

The FRP stack was visually inspected in April 1997. It appeared to be in as-new condition with no signs of erosion or corrosion.

## FGD SPRAY HEADER SUPPORTS

In the SHU absorber, the A and B headers are supported on Hastelloy beams. All other headers are supported on vulcanized rubber-laminated carbon steel beams with Hastelloy end plates. During the 1996 inspection of Unit 1, a greenish scale deposit was observed on the A header support; the scale was removed and no subsequent corrosion was observed. The cause of the scale was not determined.

## RUBBER LAMINATES

The turning vanes and absorber entry doors were factory-coated with vulcanized rubber. During the March/April 1997 absorber inspection, the rubber laminate was blistered in several locations and, in some cases, pieces of rubber were completely torn away, exposing the metal underneath. Some of the missing rubber pieces were found plugging a few of the slurry spray nozzles. These rubber laminate pieces apparently entered the recycle spray loop via the recycle pump suction after falling into the absorber sump. During the September/October 1997 absorber inspections, the rubber laminate was partially detached from the east-west flow splitter in the Unit I cocurrent section in two locations, ca. 6-12 $in^2$ each. Also during this inspection bubbles were found in the rubber laminate on the Unit 2 mist eliminator supports. No remedial action was taken.

All of the rubber-lined process tanks were inspected in March/April 1997 and were in good condition with the exception of a few small bubbles in the linings; these did not require repair.

## FIBERGLASS PIPING SYSTEM

Fiberglass pipe is used to transport gypsum slurries throughout the plant. The fiberglass piping system was in good condition as of April 1998 with the following exceptions.

- The fiberglass slurry recycle pipes developed cracks near the gusset plates holding the clarified water flush valves; the cracks were first observed in late 1996. The cracks appeared to be due to the clarified water pipes being rigidly held in place while the slurry recycle pipes are allowed to twist and flex.

- The fiberglass slurry bleed line from the Unit 1 absorber cracked in early 1997. The cause of the crack was not apparent.

- Severe external erosion of the fiberglass elbows on the Unit 2 “D” header was due to direct impingement of slurry from a broken nozzle in the “C” header which is directly above. The elbows were replaced in October 1996.

- Internal erosion of the fiberglass pipe in the centrifuge feed loop return line was observed immediately downstream of an 8”-4” reducing elbow. The problem was believed to be due to high slurry velocity caused by the reducing elbow. The eroded pipe was replaced in 1997 and the piping system was redesigned to reduce the number of turns and eliminate reducing elbows. The erosion problem has not occurred since the redesign.

## SLURRY SPRAY NOZZLES

The original recycle header nozzles were pigtail-type, silicon carbide, spray nozzles. These nozzles experienced substantial plugging and breaking problems. To overcome the breaking problem, an alternative nozzle material, Stellite®, was tested. Thirty-three broken silicon carbide nozzles (25 from cocurrent headers and 8 from countercurrent headers) were replaced with pigtail nozzles made of Stellite® during the 1996 maintenance outage of Unit 2. All of the Stellite® nozzles remained intact as of the September/October 1997 outages.

The pigtail nozzles frequently plugged with pieces of rubber that sloughed off of rubber-coated components in the absorber or with pieces of dislodged scale from the absorber walls. The rubber or scale debris lodged in the nozzle tip, where the clearance narrows. Recycle slurry then accumulated around the plug and formed a hard deposit that enlarged and eventually closed off the nozzle completely. A sample of a nozzle deposit was taken during the 1996 inspection. The deposit was mostly gypsum with smaller amounts of iron, aluminum and silicon (table 4.12-1).

Two approaches were tested to overcome the plugging problem. An alternative nozzle design with larger clearance was tested, and a pump suction inlet perforated plate strainer was installed on one of the recycle pumps to prevent large pieces of scale and rubber debris from entering the pump. The alternative nozzles were a deflector cone-type design. Twelve nozzles on the B header and 4 nozzles on the F header in Unit 2 were replaced during the March/April 1997 maintenance outage with the alternative design. The strainer consisted of a metal box made from ¼-in thick perforated plate with 1-in diameter holes on 1.25-in triangular-pitch centers, as shown in Figure 4-12-2. The strainer was installed on the recycle pump suction inlet of the Unit 2 E header (which has the pigtail-type nozzles) during the March/April 1997 maintenance outage.

The absorber was briefly inspected in late May 1997 during an unscheduled boiler outage (tube leak). The alternative nozzles on the B and F headers and the pigtail nozzles on the E header were all found to be plug free. As a comparison, a few of the original pigtail design nozzles (which were cleaned during the 1997 maintenance outage) on the A header were already plugged.

The nozzles were examined again during the September/October 1997 inspection. None of the alternative nozzles were plugged, although some had a substantial buildup on the deflector plates. The deflector plate supports were broken on three of the nozzles, apparently due to bad welds; they were rewelded and returned to service. None of the pigtail nozzles on the E header (which had the pump suction strainer) were plugged. The strainer was partially blocked by several pieces of rubber that had sloughed off of rubber-coated components in the absorber apparently, the blockage was not severe enough to affect the E pump performance during operation. As a comparison, three F header nozzles and four G header nozzles, which did not have pump strainers, were plugged with pieces of rubber.

In summary, it appears that the pump strainers were successful in preventing pieces of tramp rubber from plugging the nozzles. Nozzles made from silicon carbide experienced substantial breakage. The alternative design nozzles were less likely to plug than the pigtail nozzles.

### Nozzle Flanges

The 33 Stellite® pigtail nozzles in Unit 2 have a 316 SS flange for attachment to the fiberglass piping. The stainless steel eroded on several of the A and B headers. Apparently, gaps formed between the flanges when the flange bolts became loose; recycle slurry leaked at a high velocity through the gaps and eroded the flanges. The flange bolts probably loosened from vibration and thermal expansion.

## VALVES

The carbon steel butterfly valves downstream of the oxidation air blowers corroded slightly. However, because air-tight shutoff is not required, these valves were simply cleaned during scheduled outages and returned to service.

The carbon steel bodies of the centrifuge cake wash valves corroded and the Teflon® valve seats often developed cuts during service, resulting in leaks. The valve bodies were replaced with stainless steel bodies and the seats were replaced with reinforced Teflon® valve seats in early 1997. The corrosion and leaks have not recurred on these valves.

## TANKS

All of the process tanks were inspected in March and April 1997. All were in good shape with the exception of the following.

- Severe corrosion of the bolts on two of the three agitator blades in both of the fresh slurry feed tanks was found. It was not clear if the bolts were properly coated with rubber prior to installation. The bolts were replaced with rubber-coated Hastelloy bolts.

- Scale on the walls of the secondary hydrocyclone feed tank was 6 to 8 in thick.
- The drain nozzle on the clarified water tank corroded because of improper flakeglass coating. The nozzle was re-sleeved and recoated in 1997. No additional corrosion has occurred since.

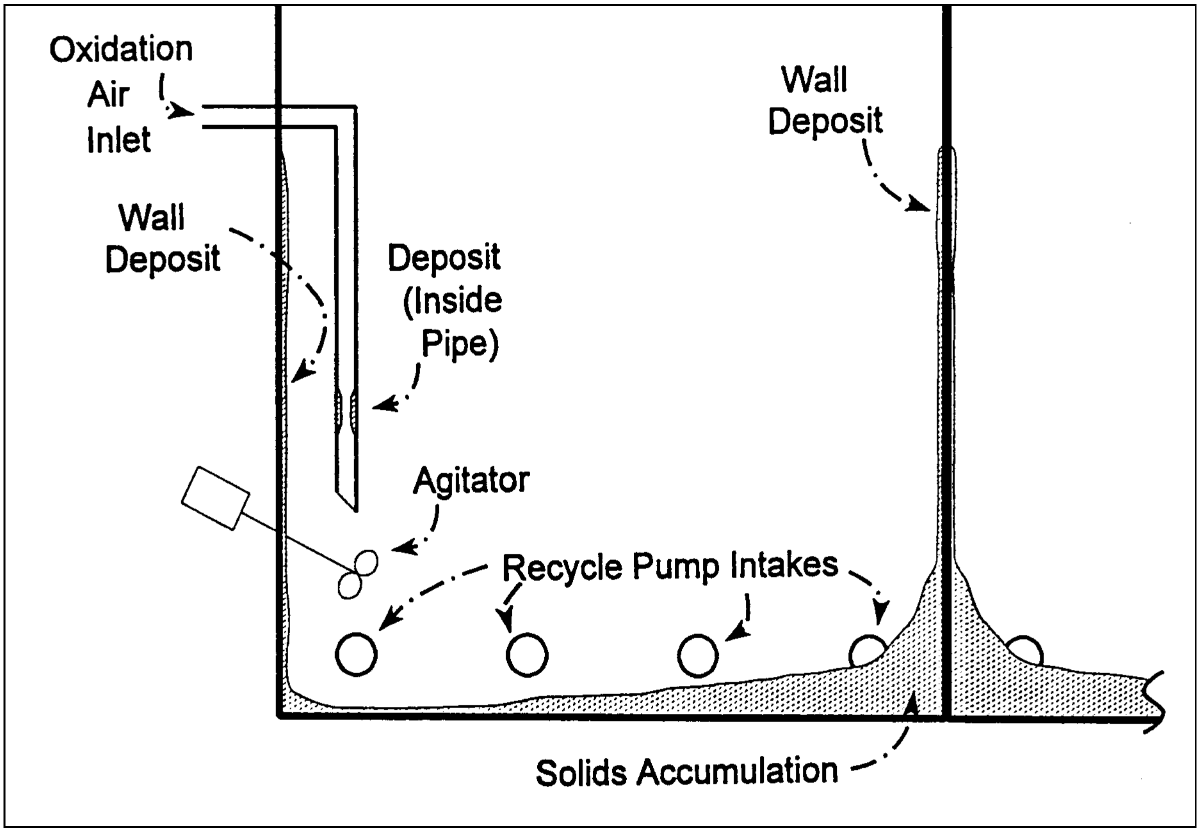
# TABLE 4.12-1
# ANALYSES (WT%, AS DETERMINED) OF DEPOSITS, GYPSUM PRODUCT, LIMESTONE FEED, AND ESP ASH

|  | Date Collected | Free Water | Combined Water | CaO | MgO | $Na_2O$ | $K_2O$ | $SiO_2$ | $A1_2O_3$ | $Fe_2O_3$ | SO3 | Cl | F | $CO_3$ | Total Carbon |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mist eliminator deposit - Unit 1 | 4/16/96 |  |  | 25.09 | 0.54 | 0.10 | 0.93 | 11.55 | 3.10 | 0.95 | 36.61 |  |  | 0.05 |  |
| Recycle spray nozzle deposit - Unit 2 | 3/18196 | 2.59 | 9.56 | 32.99 | 0.57 | 0.14 | 0.11 | 1.02 | 0.28 | 0.07 | 4801 | 1.27 |  | 0.06 |  |
| Oxidation air pipe deposit - Unit 1 | *4/16/96* | 5.58 | 19.14 | 27.30 | 1.06 | 0.10 | 0.24 | 3.26 | 0.87 | 1.11 | 37.00 | 1.56 |  | 0.74 |  |
| Absorber floor solids - Unit 2 | 3/18/96 | 12.77 | 20.75 | 24.96 | 0.86 | 0.08 | 0.05 | 1.27 | 0.13 | 0.08 | 35.49 |  |  | 1.24 |  |
|  | 4/16/96 | 0.51 | 19.11 | 30.63 | 0.29 | 0.05 | 0.22 | 2.66 | 0.78 | 0.84 | 42.26 | 0.22 |  | 0.11 |  |
| Absorber wall scale - Unit 1 | 4/16/96 | 0.73 | 19.61 | 29.87 | 0.33 | 0.04 | 0.26 | 2.37 | 0.76 | 0.78 | 42.38 | 0.27 |  | 0.21 |  |
| Gypsum Product - Unit 1 | 3/18/96 | 7.42 | 18.99 | 30.65 | 0.10 | 0.02 | 0.02 | 0.25 | 0.08 | 0.09 | 43.59 | 0.01 |  | 0.68 |  |
| Gypsum Product - Unit 2 | 4/16/96 | 7.66 | 18.80 | 29.02 | 0.18 | 0.01 | 0.06 | 1.00 | 0.16 | 0.12 | 43.16 | 0.01 |  | 0.59 |  |
| Limestone | 4/16/96 | 0.01 | 0.12 | 48.14 | 3.08 | 0.02 | 0.14 | 1.87 | 0.42 | 0.14 | 0.12 | 0.02 |  | 57.1 |  |
|  | 4/16/96 |  |  | 2.62 | 0.75 | 0.66 | 1.69 | 47.15 | 23.00 | 17.31 | 1.14 |  |  |  |  |
|  | 4/16/96 |  |  | 2.72 | 0.76 | 0.66 | 1.72 | 48.27 | 23.45 | 17.45 | 1.12 |  |  |  |  |
| Absorber wall scale - Unit 1 | 9/1 7/97 | 0.36 | 19.49 | 31.99 | 0.15 | 0.02 | 0.04 | 0.88 | <0.02 | 0.27 | 46.82 | 0.03 | 0.62 | 0.04 | 0.28 |
| Absorber wall scale - Unit | 9/17/97 | 2.38 | 19.55 | 32.14 | 0.22 | 0.02 | 0.05 | 1.05 | <0.02 | 0.19 | 48.25 | 0.40 | 0.52 | 0.03 | 0.32 |
| Absorberwall scale- Unit 2 | 10/28/97 | 0.55 | 18.67 | 32.17 | 0.15 | 0.02 | 0.11 | 1.67 | <0.01 | 0.72 | 46.01 | 0.12 | 1.06 | 0.29 | 0.93 |
| Absorber wall scale - Unit 2 | 10/28/97 | 1.67 | 19.36 | 30.91 | 0.10 | 0.01 | 0.04 | 1.02 | <0.02 | 0.24 | 47.74 | 0.15 | 0.66 | 0.03 | 0.48 |
| Absorberwall scale- Unit2 | 10/28/97 | 0.26 | 19.51 | 31.57 | 0.05 | 0.01 | 0.03 | 0.98 | <0.01 | 0.29 | 48.26 | 0.05 | 0.59 | 0.09 | 0.25 |

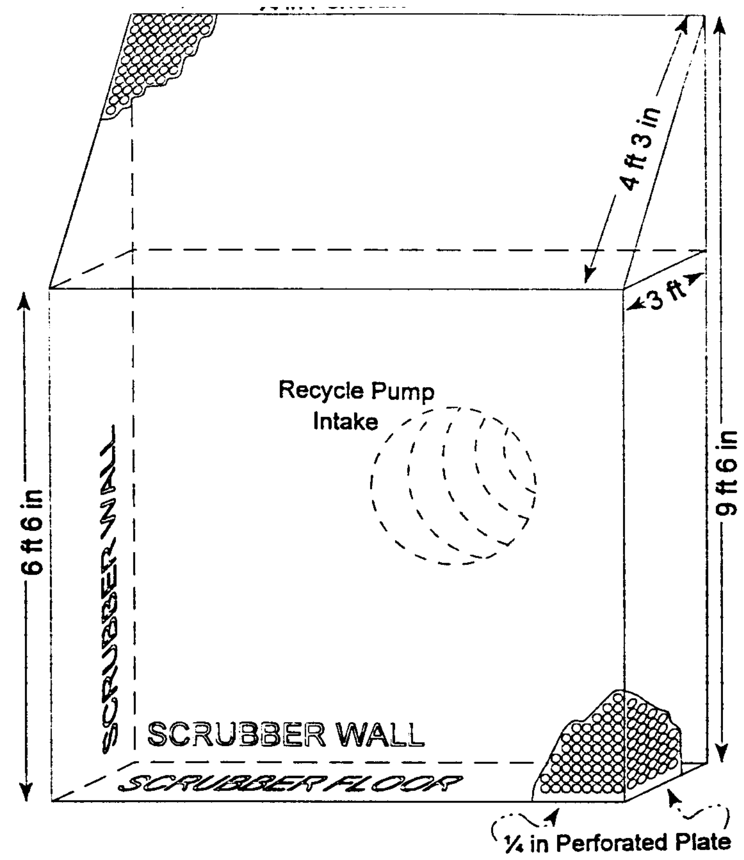
## FIGURE 4.12-1

## SCHEMATIC SHOWING APPROXIMATE LOCATIONS OF SOLIDS DEPOSIT IN ABSORBER

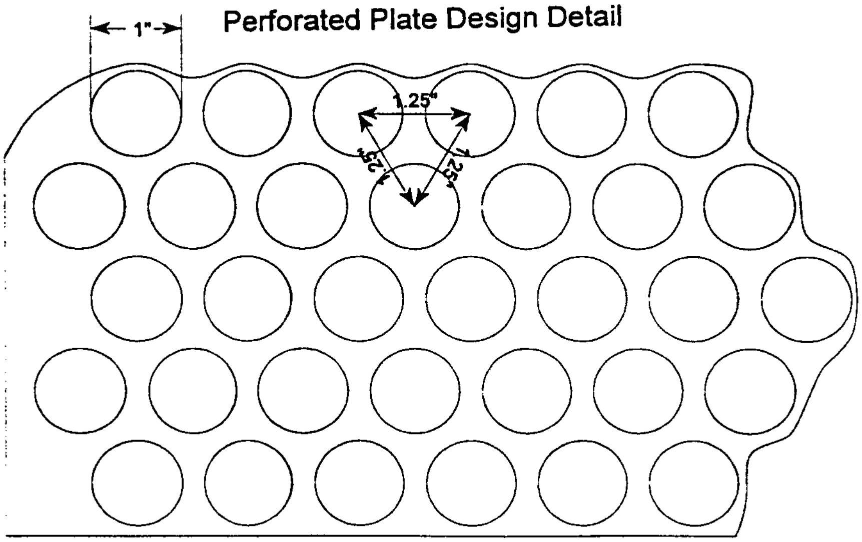
(Figure is not to scale)



## Figure 4.12-2
## Schematic of Pump Intake Strainer



Perforated Plate Design Detail



DE-FC22-93PC92642

# MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

## PROJECT PERFORMANCE AND ECONOMICS REPORT

### FINAL REPORT - VOLUME II of II

NEW YORK STATE ELECTRIC & GAS CORPORATION

# 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 $NO_x$ 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, $Cr^{+6}$, 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, $Cr^{+6}$, 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 $SO_2$ emissions by at least 90%. The project also consisted of combustion modifications and selective non-catalytic reduction (SNCR) technology to reduce $NO_X$ emissions. Goals of the demonstration included up to 98% $SO_2$ removal efficiency while burning high-sulfur coal, 30% reductions in $NO_X$ 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).

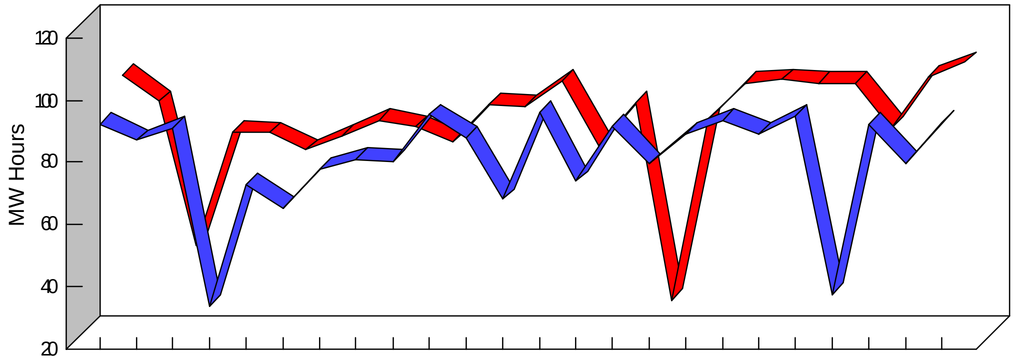
Quarterly environmental monitoring reports were developed in support of NYSEG's requirements to the U.S. Department of Energy (DOE) for project funding through the Clean Coal Technology (CCT) Program. The environmental monitoring reports provided a comprehensive description of the environmental monitoring 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, $NO_X$ 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 $NO_X$ emissions and LOI at various economizer $O_2$ levels and various mill classifier speed settings. At reduced loads (120 & 90 MW), measured $NO_X$ and LOI levels were lower than predicted.

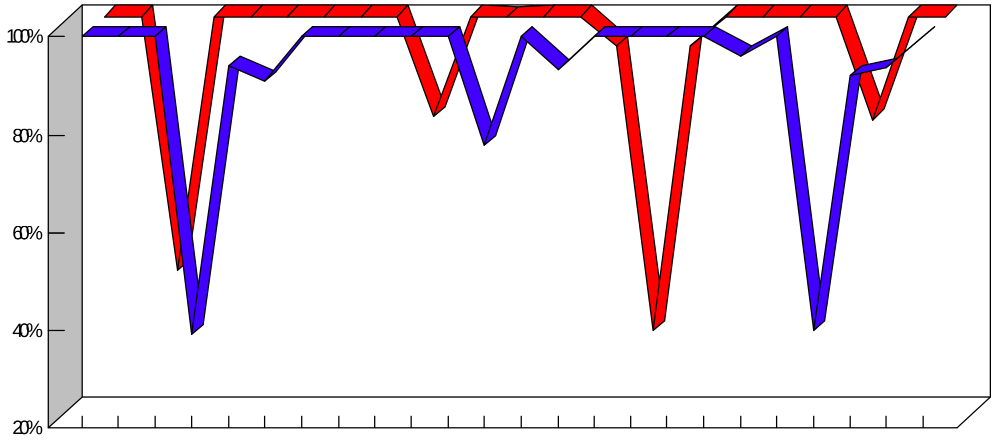
Availability and monthly load for both of Milliken's Units for 1995 and 1996 are listed in Figure 5.2-1 and 5.2-2 respectively.

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



| Month | J | F | M | A | M | J | J | A | S | O | N | D | J | F | M | A | M | J | J | A | S | O | N | D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 🟦 Unit 1 | 92 | 87 | 91 | 34 | 73 | 65 | 78 | 81 | 80 | 95 | 88 | 68 | 96 | 74 | 92 | 79 | 89 | 93 | 89 | 95 | 37 | 92 | 80 | 93 |
| 🟥 Unit 2 | 101 | 92 | 46 | 83 | 82 | 77 | 81 | 86 | 84 | 79 | 91 | 91 | 99 | 78 | 92 | 28 | 87 | 98 | 99 | 98 | 98 | 84 | 100 | 105 |

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



| Month | J | F | M | A | M | J | J | A | S | O | N | D | J | F | M | A | A | J | J | A | S | O | N | D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 🟦 Unit 1 | 100% | 100% | 100% | 39% | 94% | 91% | 100% | 100% | 100% | 100% | 100% | 78% | 100% | 93% | 100% | 100% | 100% | 100% | 96% | 100% | 40% | 92% | 94% | 100% |
| 🟥 Unit 2 | 100% | 100% | 48% | 100% | 100% | 100% | 100% | 100% | 100% | 80% | 100% | 100% | 100% | 100% | 94% | 36% | 94% | 100% | 100% | 100% | 100% | 79% | 100% | 100% |

## 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 $SO_2$, $NO_X$, TSP, $CO_2$ 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 $SO_2$, $NO_X$, 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 $SO_2$ concentration was 110.4 ppm and the average emission rate was .3045 lb/mmBTU. The average concentration of $NO_X$ 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 $SO_2$ concentration was 244.5 ppm and the average emission rate was .6018 lb/mmBTU. The average concentration of $NO_X$ 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 $SO_2$, $PM_{10}$ and $NO_X$. Additional parameters ($O_3$, 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 $SO_2$, and $O_3$ before and after the scrubber retrofit,
- to demonstrate the scrubber's effectiveness in reducing ambient levels of $SO_2$ and $NO_X$.

In order to site the locations for the ambient monitoring program, NYSEG performed a dispersion modeling analysis in 1991 for three pollutants ($SO_2$, $NO_2$ and $NH_3$) 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 $SO_2$, $NO_2$, TSP, $PM_{10}$ and 10-meter wind speed, wind direction and temperature. One of these sites (North site) also monitored $O_3$. 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 $SO_2$, $NO_X$, $CO_2$ 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 $SO_2$ 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 $SO_2$ average for the 4-year period was 6 ppb (annual AAQS 30 ppb). The highest hourly average $NO_2$ and $NO_X$ concentrations for the North Site were 43 ppb and 83 ppb respectively, with a 4-year average of 5 ppb for $NO_2$ and 7 ppb for $NO_X$ (annual AAQS for $NO_2$ 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 $PM_{10}$ concentration during this 4-year period was 64.2 $\mu g/m^3$ (43% of AAQS). The highest 24-hour TSP concentration was 50.5 $\mu g/m^3$ (34% of the secondary AAQS).

The highest hourly average $SO_2$ 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 $SO_2$ average for the 4-year period was 6 ppb (annual AAQS 30 ppb). The highest hourly average $NO_2$ and $NO_X$ concentrations for the East Site were 51 ppb and 279 ppb respectively, with a 4-year average of 5 ppb for $NO_2$ and 7 ppb for $NO_X$ (annual AAQS for $NO_2$ is 50 ppb). The highest 24-hour $PM_{10}$ concentration during this 4-year period was 62.2 $\mu g/m^3$ (41% of AAQS). The highest 24-hour TSP concentration was 52.2 $\mu g/m^3$ (35% of the secondary AAQS).

The highest hourly average $SO_2$ 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 $SO_2$ average for the 4-year period was 7 ppb (annual AAQS 30 ppb). The highest $NO_2$ and $NO_X$ hourly concentrations were 59 ppb and 257 ppb respectively, with a 4-year average of 6 ppb for $NO_2$ and 7 ppb for $NO_X$ (annual AAQS for $NO_2$ is 50 ppb). The highest 24-hour $PM_{10}$ concentration during this 4-year period was 50.4 $\mu g/m^3$ (34% of AAQS). The highest 24-hour TSP concentration during the period was 51.9 $\mu g/m^3$ (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 ($SO_2$)

Analyzing the four years of $SO_2$ data collection, figures 5.2-3 and 5.2-4 present the maximum hourly $SO_2$ 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 $SO_2$ concentrations respectively for each site for the calendar years 1993 through 1996. Once again, a significant reduction in average $SO_2$ levels is observed between calendar years 1993 and 1994 versus 1995 and 1996.

Looking at $SO_2$ 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 $SO_2$ changes (reductions). Figure 5.2-7 illustrates diurnal $SO_2$ concentration curves for each hour of the day for the three air quality monitoring sites. The upper plot illustrates the diurnal $SO_2$ curve for the period Feb. 1993 through Dec. 10, 1994, while the lower plot presents the $SO_2$ distributions for the period June 20, 1995 through Dec. 31, 1996. These two plots clearly show a significant reduction in ambient $SO_2$ levels at the three NYSEG air monitoring sites when comparing the pre- and post-scrubbing periods. In general, measurements showed the $SO_2$ levels to be lower by an average of 40-50% from Period I to Period II.

### Nitrogen Dioxide ($NO_2$) & Ozone ($O_3$)

Analyzing the four years of $NO_2$ data collection, figure 5.2-8 presents the maximum $NO_2$ 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 $NO_2$ 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 $NO_2$ levels during the two critical periods (pre- and post-scrubbing) some reductions in $NO_2$ levels are discernible. Figure 5.2-10 presents the diurnal $NO_2$ concentration curves for each hour of the day for the three sites. The upper plot presents the diurnal $NO_2$ levels for the period Feb. 1993 through Dec. 10, 1994, while the lower plot presents the $NO_2$ distributions for the period June 20, 1995 through Dec. 31, 1996. A comparison of these $NO_2$ diurnal concentration curves reveals modest reductions in ambient $NO_2$ 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 $O_3$ concentration levels between the two critical periods (pre- and post-scrubbing) a slight reduction in the ambient $O_3$ levels can be identified. Figure 5.2-8 presents the diurnal $O_3$ concentration curves for each hour of the day for the North site. The upper plot presents the diurnal $O_3$ levels for the period Feb. 1993 through Dec. 10, 1994, while the lower plot presents the $O_3$ distributions for the period June 20, 1995 through Dec. 31, 1996. A comparison of these $O_3$ diurnal concentration curves reveals slight reductions in ambient $O_3$ levels between the pre-and post-scrubbing periods.

As previously shown, the changes in ambient levels of $SO_2$ between the pre- and post-scrubbing periods were significant (approximately 40-50% reductions). The changes in $NO_2$ and $O_3$ ambient levels, although also apparently being reduced, were not as significant. In order to determine whether the changes in $NO_2$ and $O_3$ 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 $NO_2$ monitoring sites and the one $O_3$ site for the two critical periods (pre- and post-scrubbing).

The results of the $NO_2$ statistical T-tests indicate that with 99.95% confidence, the changes (reductions) in $NO_2$ concentrations at the North and South sites between Periods I and II are considered significant. However, the changes (reductions) in $NO_2$ 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 $T^{l}$-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 $T^{1}$, then the difference in the average values of each data set is considered to be significant. With respect to the East site $NO_2$ data comparison, the calculated T-value was found to be less than the various confidence level $T^{l}$ values, indicating an insignificant change in the ambient $NO_2$ levels.

Similarly, the same statistical tests were conducted on the ozone ($O_3$) data collected at the North Site during the same periods. The results of the $O_3$ 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 $O_3$ 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 $T^1$-value. However, the calculated T-value was found to be greater than the 95% confidence $T^1$-value. These results indicate that with a 95% confidence level a significant change in ambient levels of $O_3$ had occurred.

In summary, based upon the statistical T-tests conducted, the changes (reductions) in ambient levels of $NO_2$ 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 $O_3$ between the pre- and post-scrubbing periods are also considered to be significant.

### Total Suspended Particulates (TSP) & Inhalable Particulate ($PM_{10}$)

Similar data comparisons were made of the total suspended particulate (TSP) and inhalable particulate ($PM_{10}$) data for the periods of sampling (i.e., $PM_{10}$: 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 $NO_X$ Concentric Firing System Level 3 (LNCFS-3) burners to reduce $NO_X$ emissions while maintaining high combustion efficiency and acceptable fly ash loss on ignition (LOI). The achievable annual $NO_X$ 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 $NO_X$ 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 $SO_2$, $NO_2$, $O_3$, TSP and $PM_{10}$ 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 $SO_2$ levels showed a reduction by an average of 40-50% over the course of the 4-year air monitoring study. The ambient $NO_2$ levels also were reduced by an average of 10-15% at the North and South sites, while very little change was observed in the $NO_2$ 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 $PM_{10}$ 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 ($SO_2$) | 5 meters |
| East Site (Lake Ridge Road) | Nitrogen Oxides ($NO$, $NO_2$, $NO_x$) | 5 meters |
| South Site (Algerine Road) | Total Suspended (TSP) and Fine Particulates ($PM_{10}$) | 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 ($O_3$) 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<br>10-50 meters<br>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

| Parameter/Function | Instrument |
|---|---|
| Sulfur Dioxide ($SO_2$) | TECO 43 |
| Nitrogen Oxides ($NO_X$) | TECO 14B/E<br>TECO 42 |
| Ozone ($O_3$) | TECO 49 |
| Particulate ($TSP/PM_{10}$) | 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<br>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<br>TECO 49 Ozone Transfer Standard |

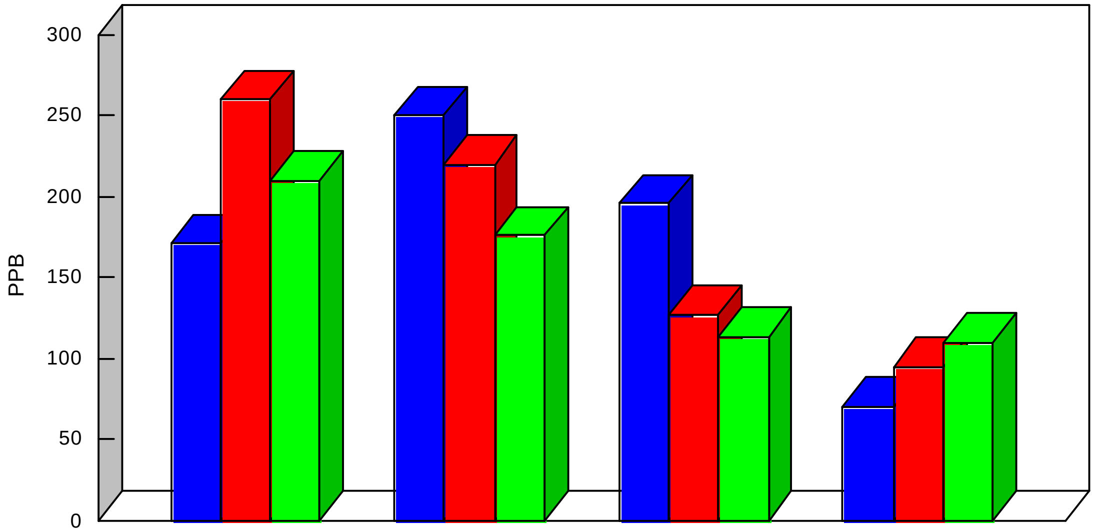
## TABLE 5.2-3
## NEW YORK STATE ELECTRIC & GAS T-TEST RESULTS ( $NO_2$ AND $O_3$)

| **Site (Parameter)** | **Period** | **Average Concentrations (ppb)** | **T Values*** |
|---|---|---|---|
| North ($NO_2$) | 6/20/95-12/31/96<br>2/l/93-12/10/94 | 5.246<br>6.159 | 16.14 |
| South ($NO_2$) | 6/20/95-12/31/96<br>2/l/93-12/10/94 | 5.531<br>6.542 | 16.91 |
| East ( $NO_2$) | 6/20/95-12/31/96<br>2/l/93-12/10/94 | 5.697<br>5.698 | 0.018 |
| North ($O_3$) | 6/20/95-12/31/96<br>2/l/93-12/10/94 | 32.370<br>32.831 | 2.726 |

Confidence Levels (n = oo):*
$T^1$ (.9995) = 3.291
$T^1$ (.95) = 1.645
$T^1$ (.60) = 0.253
***** If T is greater than $T^1$, the change is significant,

## FIGURE 5.2-3

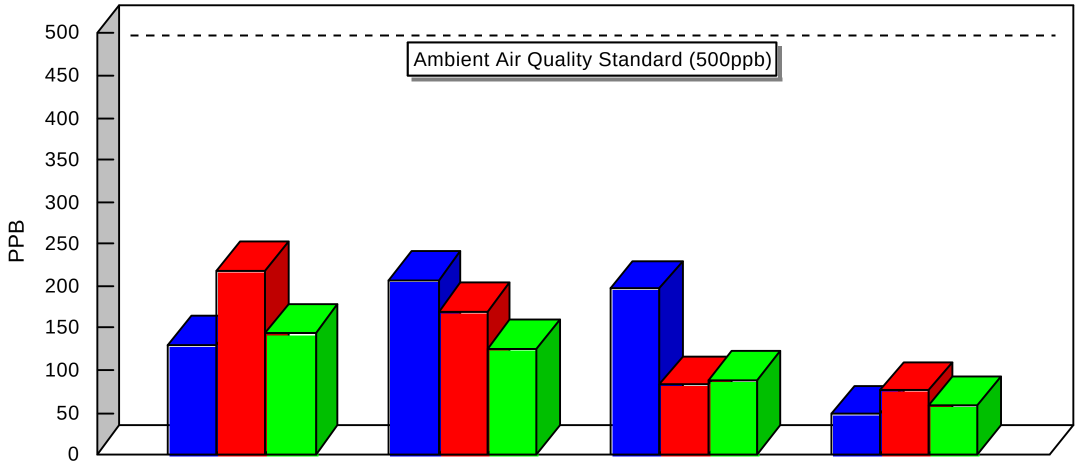
SO2 - MAXIMUM HOURLY CONCENTRATIONS



| YEAR | 1993 | 1994 | 1995 | 1996 |
|---|---|---|---|---|
| 🟦 NORTH | 171.0 | 250 | 196 | 70 |
| 🟥 SOUTH | 260.0 | 220 | 127 | 95 |
| 🟩 EAST | 210.0 | 176 | 114 | 110 |

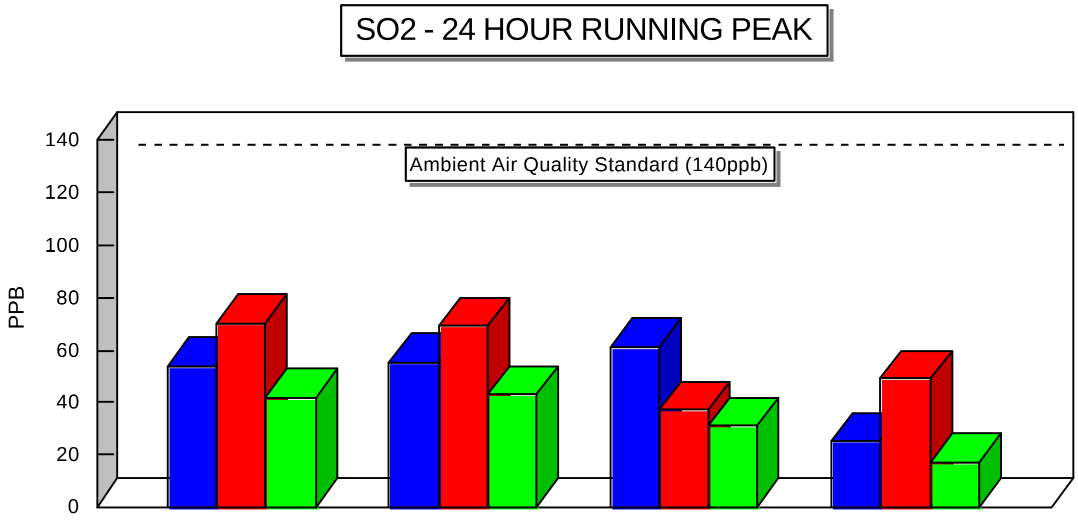
## FIGURE 5.2-4

SO2 - 3 HOUR RUNNING PEAK



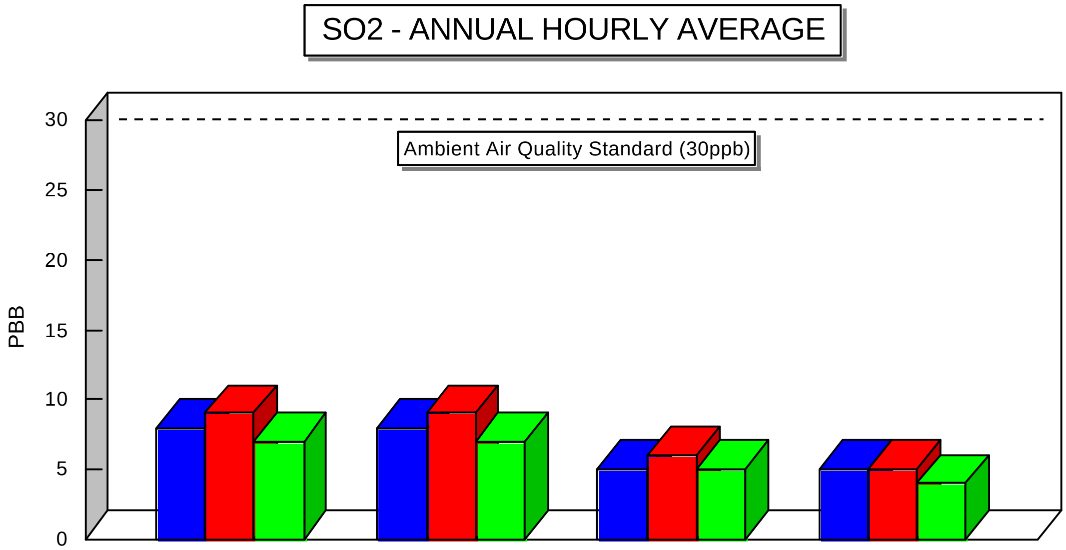
| YEAR | 1993 | 1994 | 1995 | 1996 |
|---|---|---|---|---|
| 🟦 NORTH | 131 | 206 | 196 | 48 |
| 🟥 SOUTH | 218 | 169 | 83 | 76 |
| 🟩 EAST | 144 | 125 | 89 | 58 |

## FIGURE 5.2-5



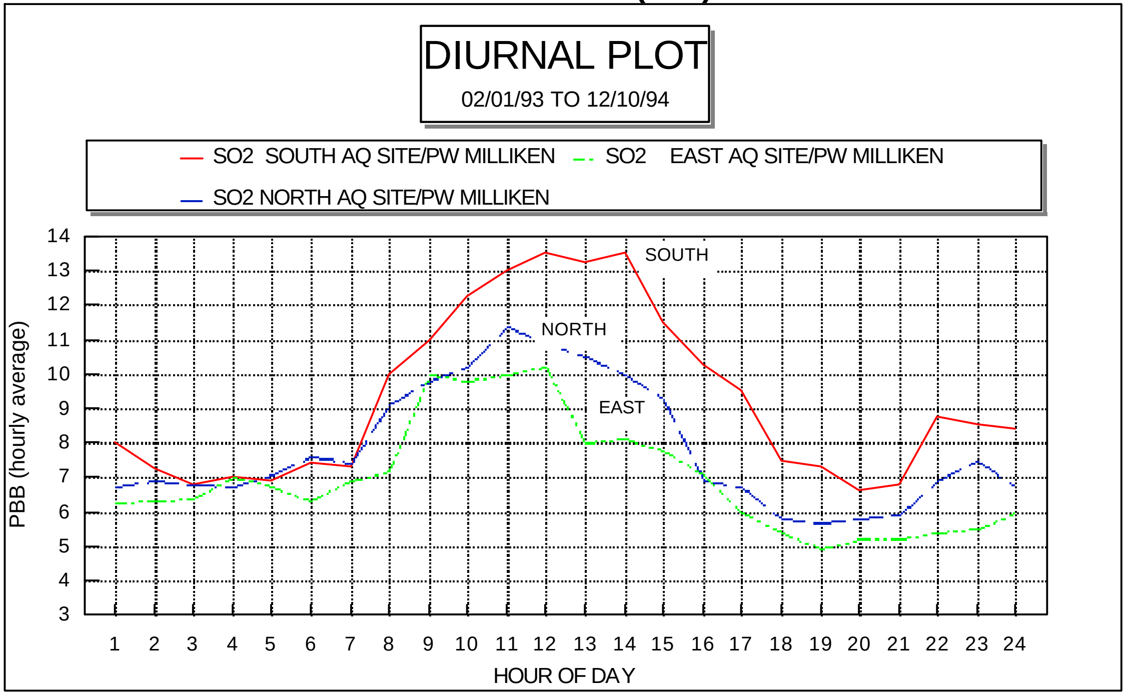
| YEAR | 1993 | 1994 | 1995 | 1996 |
|---|---|---|---|---|
| 🟦 NORTH | 54 | 55 | 61 | 25 |
| 🟥 SOUTH | 70 | 69 | 37 | 49 |
| 🟩 EAST | 42 | 43 | 31 | 17 |

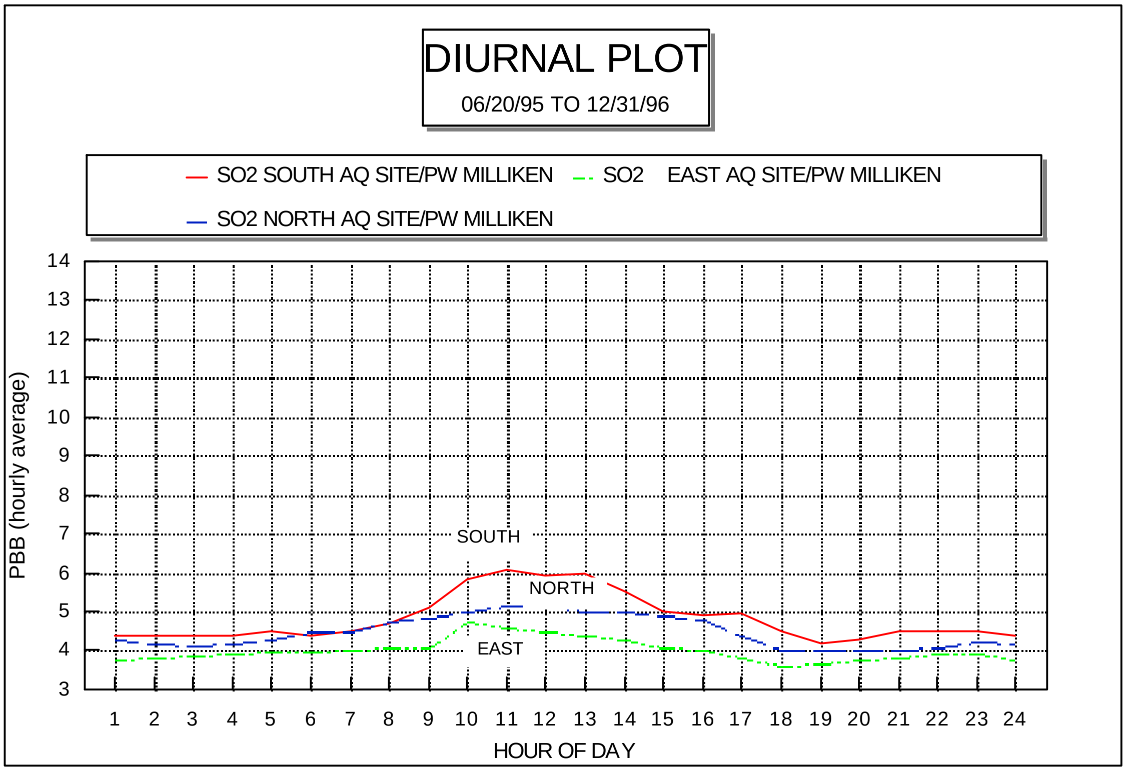
## FIGURE 5.2-6



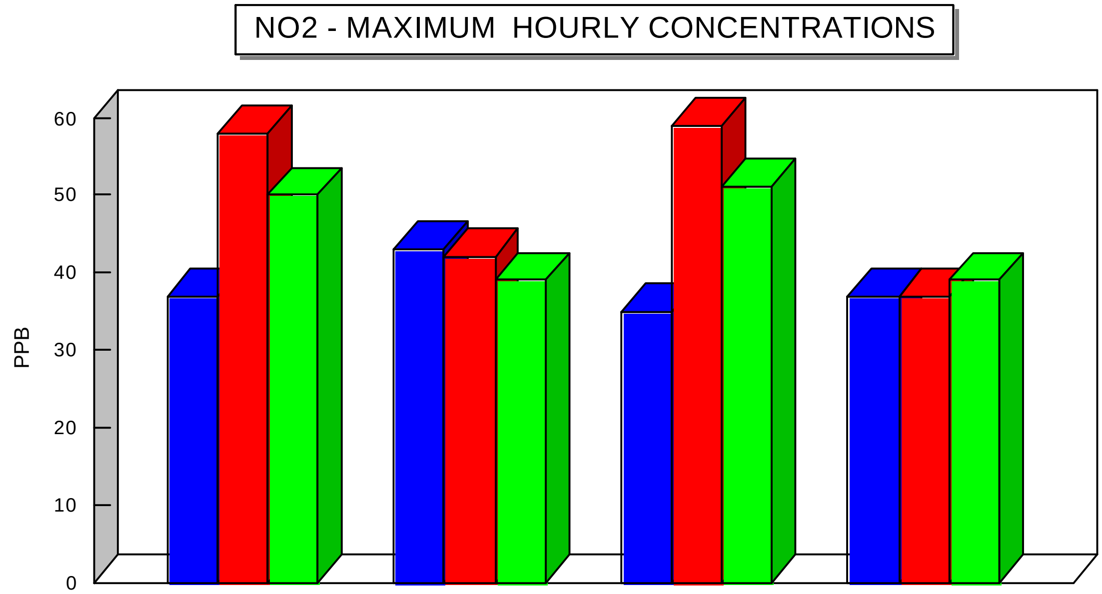
| YEAR | 1993 | 1994 | 1995 | 1996 |
|---|---|---|---|---|
| 🟦 NORTH | 8 | 8 | 5 | 5 |
| 🟥 SOUTH | 9 | 9 | 6 | 5 |
| 🟩 EAST | 7 | 7 | 5 | 4 |

## FIGURE 5.2-7
## DIURNAL VARIATION ($SO_2$) PLOTS



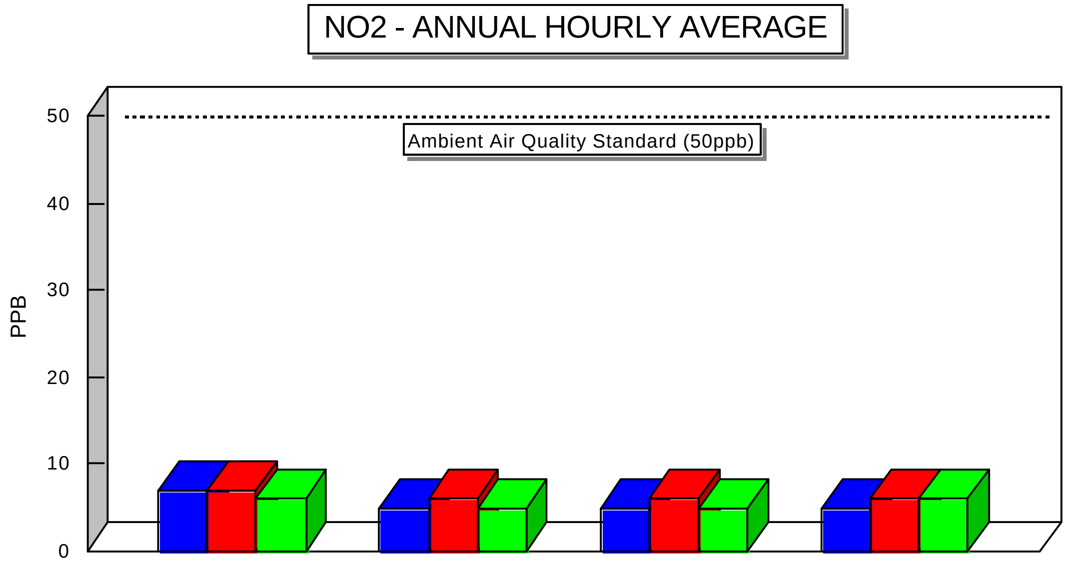


## FIGURE 5.2-8


NO2 - MAXIMUM HOURLY CONCENTRATIONS

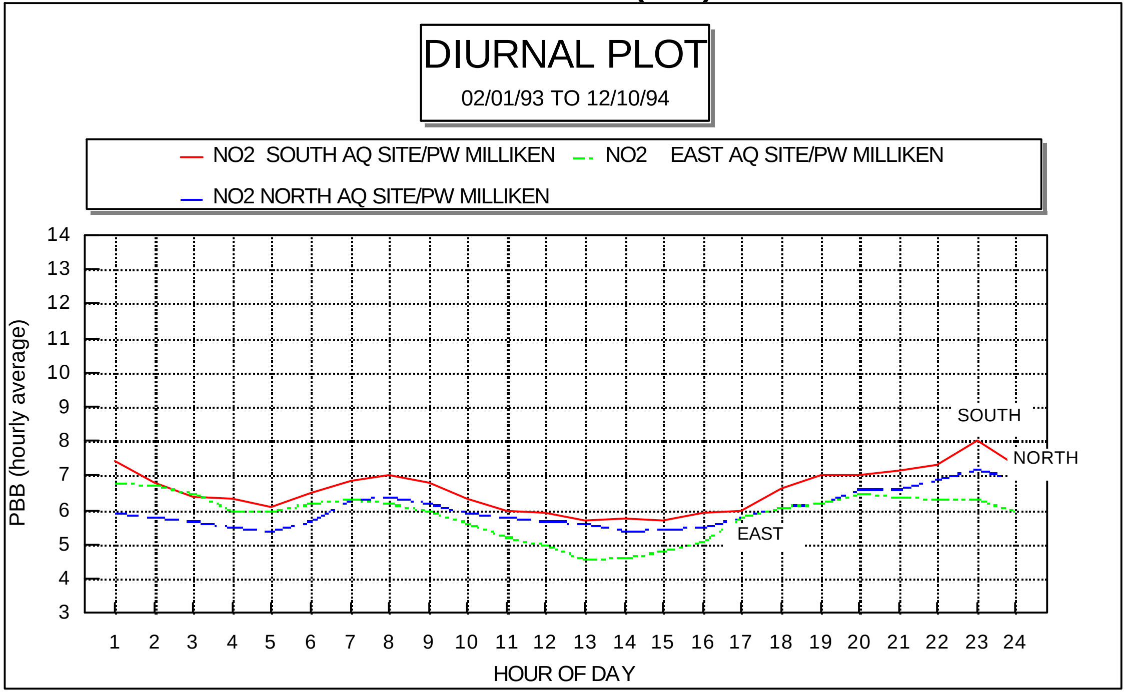
| YEAR | 1993 | 1994 | 1995 | 1996 |
|---|---|---|---|---|
| 🟦 NORTH | 37 | 43 | 35 | 37 |
| 🟥 SOUTH | 58 | 42 | 59 | 37 |
| 🟩 EAST | 50 | 39 | 51 | 39 |

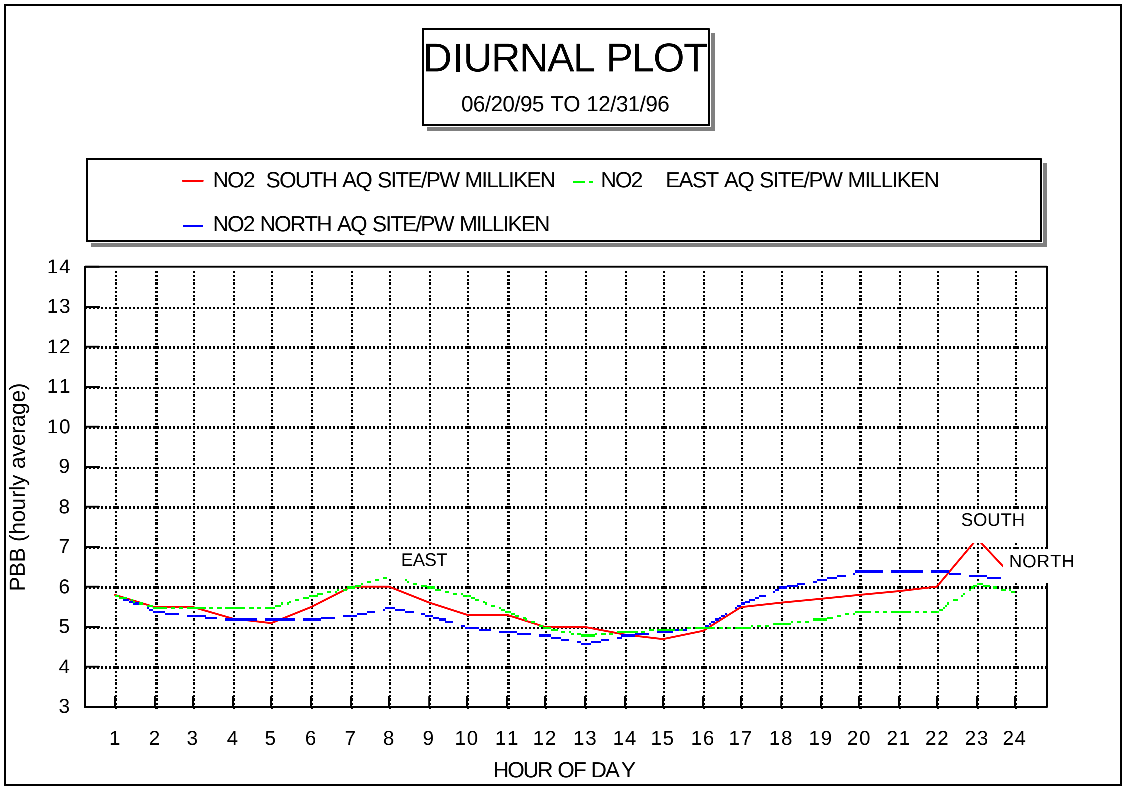
## FIGURE 5.2-9


NO2 - ANNUAL HOURLY AVERAGE

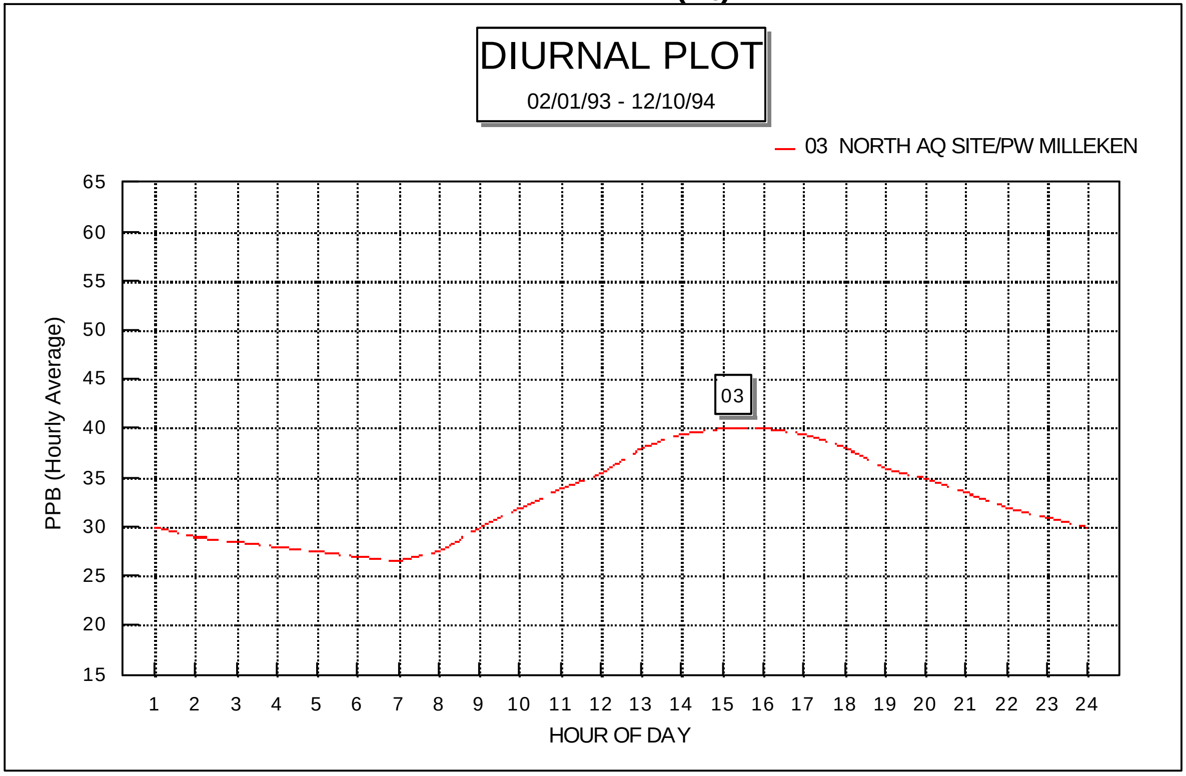
| YEAR | 1993 | 1994 | 1995 | 1996 |
|---|---|---|---|---|
| 🟦 NORTH | 7 | 5 | 5 | 5 |
| 🟥 SOUTH | 7 | 6 | 6 | 6 |
| 🟩 EAST | 6 | 5 | 5 | 6 |

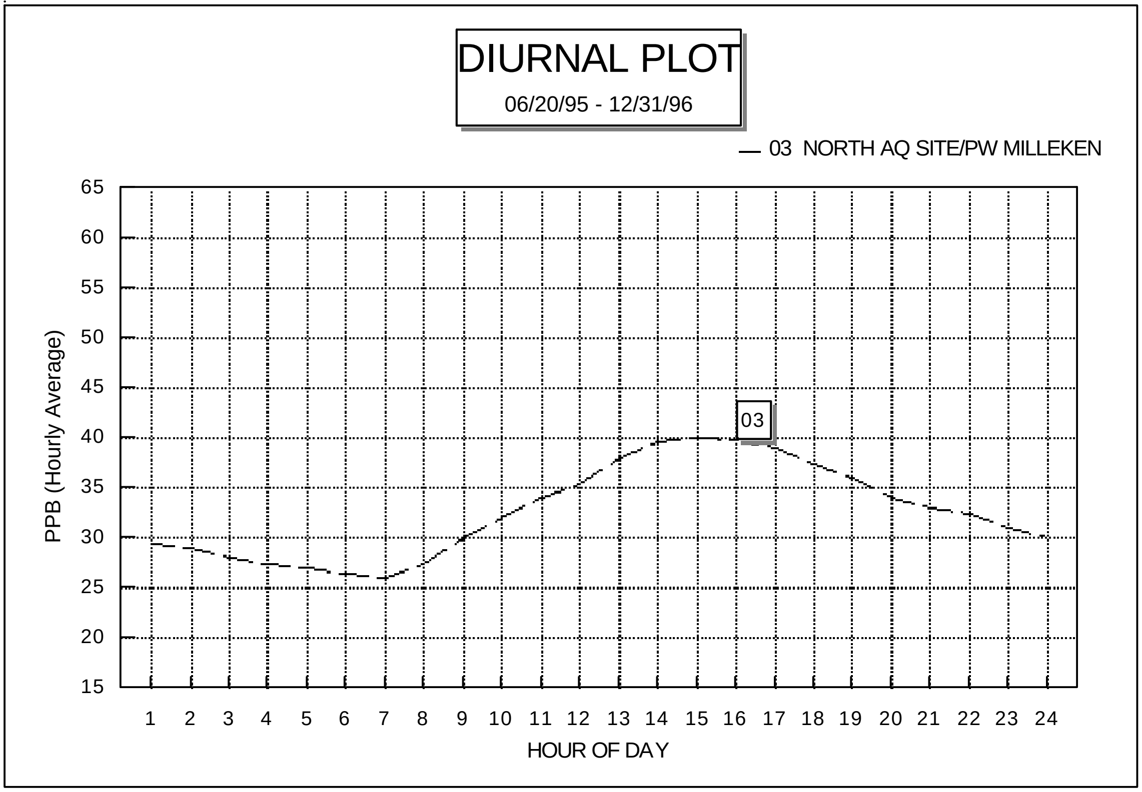
## FIGURE 5.2-10
## DIURNAL VARIATION ($NO_2$) PLOTS





## FIGURE 5.2-11
## DIURNAL VARIATION ($O_3$) 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.

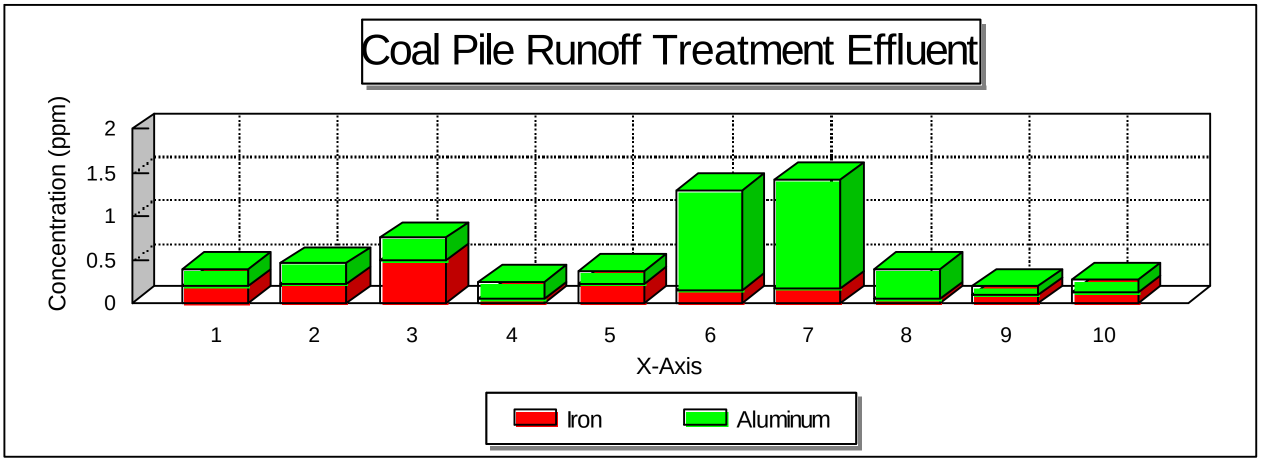
All facility wastewater discharges, including the effluent from the coal pile runoff and maintenance cleaning wastewater treatment system receives final treatment via the PWRF system which uses API separators and gravity sand filtration prior to discharge. Solids from the coal pile basin, facility lift 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 | | | | 4,814,419 | | | | 4,042,333 | | | | |
| Chlorine, residual | mg/l | 0.2 | | | | 0.2 | | | | 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

| Groundwater Parameters | Form | Units | Frequency* |
|---|---|---|---|
| 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

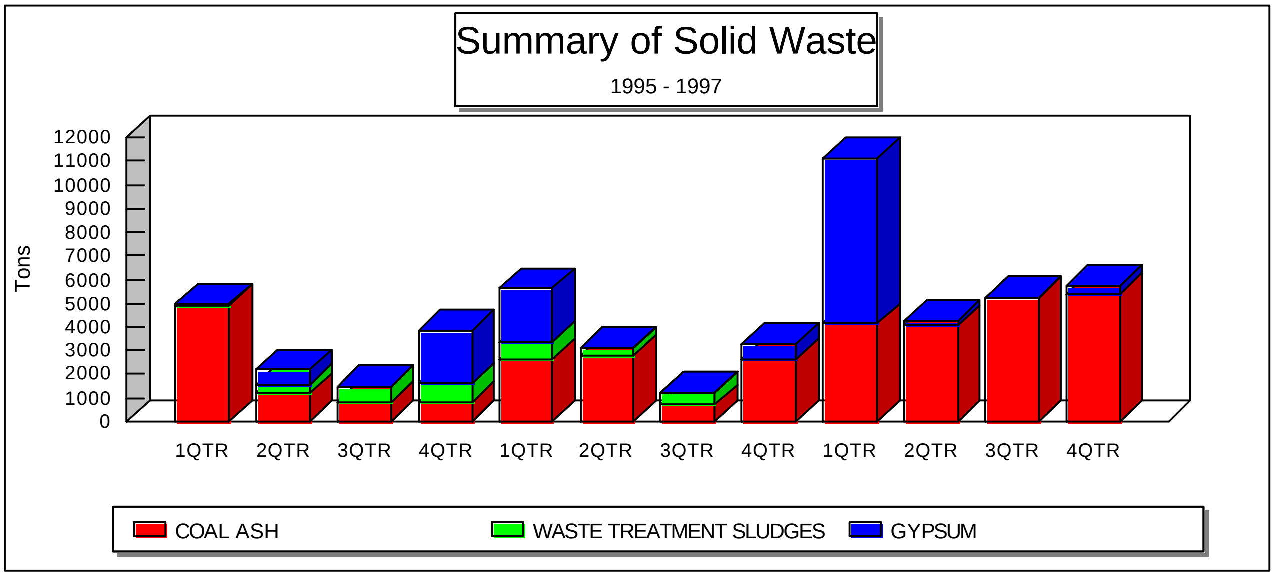
Milliken Station operates a solid waste disposal area east of the plant which encompasses approximately 41 acres. The disposal area began operation in 1978 and accepted primarily combustion byproducts from Milliken Station which included fly ash, bottom ash and pyrite rejects. In addition the facility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

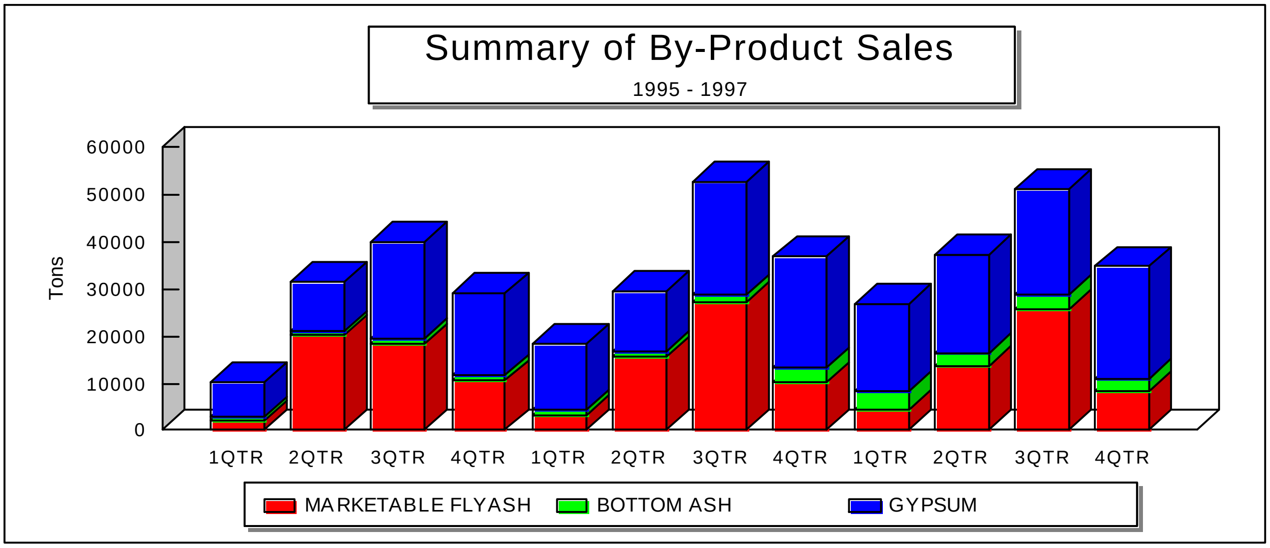
**FIGURE 5.2-13**



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

| Chemical Composition | Percentage by Weight |
|---|---|
| Calcium Chloride ($CaCl_2$) | 57 |
| Magnesium Chloride ($MgCl_2$) | 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 $CaSO_4$. 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 |
| $CACO_3$ (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 ELMENTS (WT%)

| | | **SYNTHETIC GYPSUM** | | | | **NATURALLY OCCURING** | |
|---|---|---|---|---|---|---|---|
| | **EUROPEAN BY-PRODUCT GYPSYM** | **1** | **2** | **U.S. UTILITY BY-PRODUCT** | **PILOT PLANT BY-PRODUCT** | **1** | **2** |
| **MAJOR ELEMENTS** | | | | | | | |
| CaO | 30 - 32.6 | 32.05 | 34.17 | 32.48 | 33.93 | 31.45 | 32.05 |
| $SO_3$ | 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 |
| $Al_2O_3$ | 0.1 - 0.50 | 0.05 | 0.13 | 0.02 | 0.05 | 0.55 | 0.22 |
| $Fe_2O_3$ | 0.01 - 0.13 | 0.07 | 0.09 | 0.06 | 0.15 | 0.24 | 0.07 |
| $SIO_2$ | 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 |
| $P_2O_5$ | - | <0.01 | <0.01 | <0.017 | <0.019 | 0.01 | <0.01 |
| $K_2O$ | 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 |

| **TRACE ELEMENTS** | | | | | | | |
|---|---|---|---|---|---|---|---|
| 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 |

## 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 $SO_2$ and $NO_x$ 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 $NO_X$ 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:

<u>Boiler/ESP Process Streams</u> (triplicate samples)

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

<u>Wastewater Process Streams</u> (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/$10^{12}$ Btu - respectively.

- Hexavalent chromium levels accounted for 5.6% of total ESP inlet chromium measured or 50 lb/$10^{12}$ Btu. Hexavalent chromium was not detected in the stack exhaust stream indicating that Unit 2's $Cr^{6+}$ 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/$10^{12}$Btu and the EPA Method 29 value of 8.1 lb/$10^{12}$ 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/$10^{12}$ Btu), fluoride (4,260 lb/$10^{12}$ Btu) and sulfate ($4.09 \times 10^6$ lb/$10^{12}$ 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

| | Boiler/SP Process Streams | | | | | | Wastewater Process Streams | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Flue Gas | | | | | |
| Target Compounds | Coal Feed | Coal Mill Rejects | Bottom Ash | ESP Fly-ash | ESP Inlet | Stack | Coal Pile Run-off | Mtls Trmt Plant Outlet | PWRF Outlet | Mtls TRMT Plant Sludge |
| 1. Trace Elements | X | X | X | X | X | X | X | X | | X |
| 2. Trace Elements | | | | | | | | | | |
| 2a. Total/Hexavalent Chromium | | | | | X | X | | | | |
| 2b. Mercury | | | | | X | X | | | | |
| 3. Major Elements | | | | | | | | | | |
| 4. Solid Particulate/Ash Content | X | X | X | X | X | X | | | | |
| 5. Acid-forming Anion Precursors | X | X | X | X | X | X | X | X | X | X |
| 6. Semi-volatile Organic Compounds | | | | | | | | | | |
| 6a. Polycyclic Aromatic Hydrocarbons | | | | | X | X | | | | |
| 6b. PCDD/PCDF(1) | | | | | X | X | | | | |
| 7. Volatile Organic Compounds | | | | | | | | | | |
| 7a. | | | | | X | X | | | | |
| 7b. | | | | | X | X | | | | |
| 8. Ammonia | | | | | X | X | | | | |
| 9. CEMS Data | | | | | | | | | | |
| 9a. $NO_2$, $SO_2$, $CO_2$ (Plant CEMS | | | | | | X | | | | |
| 9b. Diluent Gases - $O_2$, $CO_2$ | | | | | X(2) | X | | | | |
| 9c. Carbon Monoxide (CO) | | | | | X | | | | | |
| 10. Ultimate Proximate Analysis | X | X | X | X | X(3) | | | | | |
| 11. Higher Heating Value | X | | | | | | | | | |
| 12. Moisture | X | X | X | X | X(3) | X | | | | |

Notes:

(1) Polychlorinated dibenzo-p-dioxins/polychlorinated dibenzofurans

(2) $CO_2$ 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)[2] |
| Cobalt | Copper | Lead |
| Manganese | Mercury (by two methods)[1] | Molybdenum |
| Nickel | Phosphorus | Selenium |
| Vanadium | | |
| | MAJOR ELEMENTS[3] | |
| Aluminum | Calcium | Iron |
| Magnesium | Potassium | Silicon |
| Sodium | Sulfur[4] | Titanium |
| | ACID-FORMING ANIONS OR PRECURSORS[5] | |
| Chloride | Fluoride | Sulfate |
| | SEMIVOLATILE ORGANIC COMPOUNDS | |
| | Polycyclic Aromatic Hydrocarbons | |
| Acenaphthene | Acenaphthylene | Anthracene |
| Benz(a)anthracene | Benzo(a)pyrene | Benzo(b)fluroanthene |
| 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-Dimenthylbenz(a)anthracene | |
| | Polychlorinated Dibenzo-p-dioxins and Polychlorinated Dibenzofurans | |
| | 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$^{6+}$) 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, $Cr^{+6}$ , 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 $SO_2$ emissions control, low-$NO_X$ burners for $NO_X$ 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 $SO_2$, $NO_X$ 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 $SO_2$ 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% $NO_X$ reduction is achieved using the low-$NO_X$ 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 $SO_2$**,** $NO_X$ 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/$10^6$ 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 $SO_3$ 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/$10^{12}$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/$Nm^3$ (excluding Method 2) and Hg(II) results ranged from 0.15-0.35 µg/$Nm^3$ (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 µg/$Nm^3$.

- 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 µg/$Nm^3$.

- 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% $NO_X$ reduction can be seen between the two test programs with baseline stack emissions falling from 452 ppm @ 3% $O_2$ to 247 ppm @ 3% $O_2$.

- 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 $O_2$ during baseline testing of 3.8% verses 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 |
| FuelType | Eastern Bituminous Coal |
| Fuel Sulfur Level | 2.2-2.4% |
| Air Pollution Control Devices | Low-$NO_x$ 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, $MW_{net}$ | 149 | 148 |
| Coal Flow Rate, klb/hr | 118.7 | 120.7 |
| Boiler $O_2$ **%** | 3.3% | 2.8% |
| FGD Inlet Opacity, % | 5.8 | 6.0 |
| $SO_2$, dry ppm @ 3% $O_2$ | | |
| FGD Inlet | 1805 | 1677 |
| FGD Outlet | 142 | 93 |
| FGD Removal Efficiency | 92.1% | 94.4% |
| $SO_3$, dry ppm @ 3% $O_2$ | | |
| FGD Inlet | 6.8 | NP |
| FGD Outlet | 5.7 | NP |
| FGD Removal Efficiency | 15.3% | -- |
| $NO_X$, dry ppm @ 3% $O_2$ (FGD Outlet) | 227 | 267 |
| $NO_X$, lb/$10^6$Btu (FGD Outlet) | 0.304 | 0.357 |
| Particulate Matter, lb/$10^6$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 $SO_3$ 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 | Inorganic Flue Gas Emissions, lb/$10^{12}$Btu | | | ESP Removal Efficiency | FGD Removal Efficiency |
|---|---|---|---|---|---|
| | ESP INLET | ESP OUTLET | STACK | | |
| **Trace Elements** | | | | | |
| 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 (1) | 26 | 35 | 2.1 | NV | NV |
| Vanadium | 1,129 | 1.1 | 0.69 | 99.90% | 39.1% |
| **Anion Precursors** | | | | | |
| 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% |
| **Particulate, lb/$10^6$Btu** | 6.35 | 0.007 | 0.014 | 99.88% | -- |
| **Major Elements** | lb/$10^6$Btu | lb/$10^{12}$Btu | lb/$10^{12}$Btu | | |
| 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

| | Trace Organic Measurements, lb/$10^{12}$Btu | | |
|---|---|---|---|
| Parameter | ESP Inlet | ESP Outlet | Stack |
| **Polycyclic Aromatic Hydrocarbons**: | | | |
| 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 |
| **PCDD/PCDF Isomers** | | | |
| 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 |
| **Volatile Organic Compounds**: | | | |
| 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, $\mu g/Nm^3$** | | | **ESP Removal Efficiency (1)** | **FGD Removal Efficiency (1)** |
|---|---|---|---|---|---|---|
| | | **ESP INLET** | **ESP OUTLET/ FGD INLET** | **FGD OUTLET/ STACK** | | |
| Hg(0) - Elemental | | | | | | |
| | **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(2) | -- | NV | 2.61 | -- | -- |
| Hg(II) - Oxidized | | | | | | |
| | **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% |
| Hg (total) - Hg Solids | | | | | | |
| | **EPA Method 29** | **0.86** | **ND<0.009** | **0.006** | **99.5%** | **--** |
| | Frontier Geoscience (3) | 0.06 | 0.07 | 0.003 | -- | -- |
| | Ontario-Hydro | -- | 0.0003 | 0.0009 | -- | -- |
| | TRIS Buffer | -- | 0.002 | 0.004 | -- | -- |
| **TOTAL Hg (4)** | | | | | | |
| | **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/$10^{12}$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 (1) | | | ESP OUTLET (2) | | | FGD OUTLET/STACK (3) | |
|---|---|---|---|---|---|---|---|---|
| | Pre-Retrofit Concentrations | Post-Retrofit Concentrations | Relative Percent Diff. | Pre-Retrofit Concentrations | Post-Retrofit Concentrations | Post-Percent Reduction (4) | Post-Retrofit Concen. | Percent Reduction(5) |
| **Particulate Matter,lb/10$^{12}$Btu** | | | | | | | | |
| | 5.75 | 6.35 | 10% | 0.060 | 0.007 | 88% | 0.014 | 77% |
| **Trace Elements lb/10$^{6}$Btu** | | | | | | | | |
| 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% |
| **Anion Precursors, lb/10$^{12}$Btu** | | | | | | | | |
| 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% |
| **Major Elements** | **lb/10$^{6}$Btu** | | | **lb/10$^{12}$Btu** | | | **lb/10$^{12}$Btu** | |
| 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 oulet 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 ($SO_2$) 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 bio-available. 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 concentratons.

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 tendancy 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 form 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:

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

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$_{dw}$). 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 Cayuuga 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 $mg/kg_{dw}$). 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 µg MeHg/g wet wt) and those actually observed in lake trout (0.26 µg 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)<br>1.00E-01(i) | 1.10E-11<br>3.30E-11 | No<br>- |
| **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)<br>1.00E-01(i) | 1.18E-12<br>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 ($SO_2$) 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)

| **Chemical** | **Discharge Rate (mg/s)** |
|---|---|
| Beryllium | 9.31xl0$^{-4}$ |
| Cadmium | 5.32xl0$^{-4}$ |
| Chromium | 8.54xl0$^{-3}$ |
| Lead | 2.89xl0$^{-3}$ |
| Manganese | 2.22xl0$^{-2}$ |
| Nickel | 5.32xl0$^{-2}$ |
| Barium | 8.87xl0$^{-1}$ |
| Sulfate | 8.43x 10$^{+2}$ |
| Fluoride | 8.87xl0$^{-1}$ |
| HCl | 2.27x 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 HCI (0.8 mg/1).

### 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 x 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/1) |
|---|---|
| HCl | $7.96x10^{-1}$ |
| Sulfate | $2.96x10^{-2}$ |
| Barium | $3.11x10^{-5}$ |
| Fluoride | $3.11x10^{-5}$ |
| Nickel | $1.87x10^{-6}$ |
| Manganese | $7.79x 10^{-7}$ |
| Chromium (VI) | $3.00x10^{-7}$ |
| Lead | $1.01x10^{-7}$ |
| Beryllium | $3.27x10^{-8}$ |
| Cadmium | $1.87x10^{-8}$ |

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

| Exposure Route | Dose | Contribution (%) |
|---|---|---|
| Drinking Water | $9.33x10^{-10}$ | 73.7 |
| Swimming in Water | $1.16x 10^{-12}$ | 0.1 |
| Fish Consumption | $3.31x10^{-10}$ | 26.2 |
| Total | $1.27x10^{-9}$ | 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 | $2.28x10^{-3}$ | 99.7 | $6.31x10^{-6}$ | 0.3 | $2.28x10^{-3}$ |
| Sulfate | $8.62x10^{-5}$ | 99.7 | $2.34x10^{-7}$ | 0.3 | $8.64x10^{-5}$ |
| Barium | $1.43x10^{-5}$ | 99.8 | $3.52x10^{-8}$ | 0.2 | $1.43x10^{-5}$ |
| Lead | $1.29x10^{-5}$ | 99.9 | $1.87x10^{-8}$ | 0.1 | $1.29x10^{-5}$ |
| Manganese | $7.53x10^{-7}$ | 14.6 | $4.41x10^{-6}$ | 85.4 | $5.16x10^{-6}$ |
| Nickel | $5.01x10^{-6}$ | 99.9 | $7.40x10^{-9}$ | 0.1 | $5.02x10^{-6}$ |
| Cadmium | $2.68x10^{-6}$ | 99.9 | $2.96x10^{-9}$ | 0.1 | $2.68x10^{-6}$ |
| Chromium (VI) | $2.23x10^{-6}$ | 99.8 | $4.75x10^{-9}$ | 0.2 | $2.23x10^{-6}$ |
| Beryllium | $2.53x10^{-7}$ | 99.8 | $5.18x10^{-10}$ | 0.2 | $2.54x10^{-7}$ |
| Fluoride | $9.07x10^{-8}$ | 99.7 | $2.47x10^{-10}$ | 0.3 | $9.09x10^{-8}$ |
| Total | $2.40x10^{-3}$ | 99.5 | $1.10x10^{-5}$ | 0.5 | $2.41x10^{-3}$ |

### TABLE 5.6-6
### HCI DOSE (MG/KG-DAY) BY EXPOSURE ROUTE

| Exposure Route | Dose | Contribution (%) |
|---|---|---|
| Drinking Water | $1.29x10^{-2}$ | 99.88 |
| Swimming in Water | $1.61x 10^{-5}$ | 0.12 |
| Total | $1.29x10^{-2}$ | 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 $\mu g/m^3$ 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 [1] | $1.94\text{xl}0^{-12}$ | mg/l |
| | Sediment [1] | $7.00\text{x}10^{-8}$ | mg/kg dry weight |
| Total Mercury | Surface Water [1] | $4.07\text{x}10^{-11}$ | mg/l |
| | Sediment [1] | $5.80\text{x}10^{-7}$ | mg/kg dry weight |
| | Prey Fish [1] | $4.26\text{x}10^{-6}$ | mg/kg wet weight for 3-year old fish |
| | Predatory Fish [1] | $1.29\text{xl}10^{-5}$ | 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 | $1.94\text{x}10^{-12}$ (1) | $3.00\text{x}10^{-6}$ (2) | $6.47\text{x}10^{-7}$ | No |
| | Sediment | $7.00\text{x}10^{-8}$ (1) | $1.50\text{x}10^{-1}$ (3) | $4.67\text{x}10^{-7}$ | No |
| Total Mercury | Surface Water | $4.61\text{x}10^{-11}$ (1) | $1.30\text{x}10^{-3}$ (4) | $3.54\text{x}10^{-8}$ | No |
| | Sediment | $5.80\text{x}10^{-7}$ (1) | $1.50\text{x}10^{-7}$ (2) | $3.87\text{x}10^{-6}$ | No |

Notes:
1. Values were estimated by incrementally varying the wastewater mercury contribution until outputs were detected by R-MCM.
2. Methymercury 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 $5.39\text{x}10^{-5}$ to $2.70\text{x}10^{-6}$ 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 *Mustela vison* | 1 [c] | 95% [d] | 5% [e] | 0.22 [f] | 0.209 Aquatic Org<br>0.011 Sediment | 0.099 [g] | 1 [b] | 14.1 [h] | 34.8 [h] |
| Bald Eagle *Haliaeetus leucocephalus* | 4.5 [i] | 99% [j] | 1% [j] | 0.585 [k] | 0.579 Aquatic Org<br>0.006 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] Opresko, 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)
[1] 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**[4] | | **TRV'** | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Mink | Bald Eagle | Mink | Bald Eagle |
| Mercury (inorganic) | Mink | 1 | 1.00 | 1 | **1.00** | **1.00** | 1.00 | $4.5 \times 10^{-1}$ |
| | Japanese quail | 1 | | 1 | | | | |
| Mercury (methylmercury) | Mink | 1 | $5.00 \times 10^{-2}$ | 2 | **1.00** | **1.00** | $5.00 \times 10^{-2}$ | $6.4 \times 10^{-2}$ |
| | Mallard | 1 | $6.4 \times 10^{-2}$ | 3 | | | | |

[1] NOAEL values used for the derivation of TRVs for the receptor species from Sample et al., 1996

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

[3] LOAEL value used for the derivation of TRVs for the receptor species from Sample et al., 1996

[4] Scaling factors calculated as follows:

Mammals: (Body weight of test species/Body weight of Receptor)$^{0.25}$

Birds:(Body weight of test species/Body weight of Receptor)$^{0}$

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

| **Species** | **Body Weight** |
|---|---|
| Bald Eagle *Haliaeetus leucocephalus* | 4.5 kg |
| Mink *Mustela vison* | 1 kg |

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

| **Mercury Species** | **Mink** | **Bald Eagle** |
|---|---|---|
| Methylmercury | 5.39x10$^{-5}$ | 1.95x10$^{-5}$ |
| Total mercury | 2.70xl 0$^{-6}$ | 2.77x10$^{-6}$ |

## 5.7 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. 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

FOWL 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. 1 88 - 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 predications 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

FOWL 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 $M^2$/yr and the transverse dispersion coefficient of 4.8 $M^2$/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 Kintigh 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 $NO_X$ 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 NOxOUT® 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-$NO_X$ BURNERS ON UTILIZATION OF FLY ASH

The following is a summary of the report entitled “Milliken Clean Coal Technology Demonstration Project Impact of Low-$NO_X$ 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 $NO_X$ emissions gathered over a five-year (1992-1996) period from the Milliken Station demonstrated that a 39% reduction in $NO_X$ was achieved using LNCFS-3 low $NO_X$ 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-$NO_X$ 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 $NO_X$ 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+% $NO_X$ 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 $NO_X$ 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 $NO_X$ emissions (30-day rolling average) for the two units were averaged individually and the monthly values used to monitor the $NO_X$ emissions from the station.

## DISCUSSION

### $NO_X$ Emissions

Table 5.8.1-1 contains the monthly average from August 1992 through December 1996 for the $NO_X$ emissions for Unit 1 and Unit 2. The $NO_X$ 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 $NO_X$ 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 $NO_X$ emissions decreased after the LNCFS-3 burner systems were installed. The specific amount of $NO_X$ 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 $NO_X$ 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% $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ 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.

| | Before Conversion | After Conversion |
|---|---|---|
| Date | 11/19-20/93 | 10/17-18/95 |
| Ash | 7.23% | 8.6% |
| Sulfur | 1.8% | 1.75% |
| $H_20$ | 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 $NO_X$ emission analysis, LOI values, and standard deviation are shown in the table below.

| | Unit 1 | | Unit 2 | |
|---|---|---|---|---|
| | LOI %[1] | Std Dev | LOI %[2] | Std Dev |
| Before Burner Conversion: | 3.32 | 0.37 | 3.21 | 0.41 |
| After Burner Conversion: | 3.57 | 0.34 | 2.92 | 0.38 |

[1] Averaged: March 1994 to December 1996
[2] 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% $NO_X$ 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 | Per-cent 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 $NO_X$.

## TABLE 5.8.1-1
## NO$_X$ 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** |  |
|---|---|---|---|---|
| **Date** | **LOI** | **Standard Dev.**[1] | **LOI** | **Standard Dev.**[1] |
| 1/92 | 3.29 | 0.44 | 2.63 | 0.40 |
| 2/92 | 2.80 | 0.29 | 2.61 | 0.35 |
| 3/92 | 3.12 | 0.40 | 2.79 | 0.49 |
| 4/92 | 3.06 | 0.56 | 3.22 | 0.79 |
| 5/92 | 2.95 | 0.63 | 3.02 | 0.63 |
| 6/92 | 3.28 | 0.45 | 3.25 | 0.46 |
| 7/92 | 3.38 | 0.59 | 3.05 | 0.56 |
| 8/92 | 3.64 | 0.40 | 3.44 | 0.31 |
| 9/92 | 3.25 | 0.77 | 2.89 | 0.77 |
| 10/92 | 3.56 | 0.40 | 3.35 | 0.44 |
| l1/92 | 2.73 | 0.49 | 2.03 | 0.56 |
| 12/92 | 3.15 | 0.57 | 2.75 | 0.63 |
| 1/93 | 3.74 | 0.35 | 3.64 | 0.36 |
| 2/93 | 3.67 | 0.34 | 3.65 | 1.01 |
| 3/93 | 4.16 | 0.66 | 3.43 | 0.76 |
| 4/93 |  |  | 3.29 | 0.71 |
| 5/93 |  |  | 2.52 | 0.37 |
| 6/93 |  |  | 3.05 | 0.44 |
| 7/93 |  |  | 3.31 | 0.90 |
| 8/93 | 4.70 | 1.20 | 3.68 | 0.36 |
| 9/93 | 5.10 | 1.57 | 3.55 | 0.30 |
| 10/93 | 4.15 | 0.70 | 3.82 | 0.24 |
| 11/93 | 3.51 | 0.53 | 3.23 | 0.45 |
| 12/93 | 3.27 | 0.24 | 3.26 | 0.30 |
| 1/94 | 3.43 | 0.15 | 3.31 | 0.27 |
| 2/94 | 2.56 | 0.39 | 3.24 | 0.39 |
| 3/94 | 4.51 | 1.11 | 3.29 | 0.41 |
| 4194 | 4.28 | 1.05 | 3.55 | 0.31 |
| 5/94 | 3.20 | 0.47 | 3.53 | 0.52 |
| 6/94 | 3.57 | 0.46 | 3.83 | 0.94 |
| 7/94 | 3.04 | 0.69 |  |  |
| 8/94 | 3.35 | 0.80 |  |  |
| 9/94 | 3.84 | 0.57 |  |  |
| 10194 | 3.78 | 0.60 |  |  |
| 11/94 | 3.25 | 0.56 |  |  |
| 12/94 | 2.98 | 0.43 | 3.71 | 0.50 |
| 1/95 | 3.40 | 0.06 | 3.18 | 0.18 |
| 2/95 | 3.79 | 0.49 | 4.04 | 0.81 |
| 3/95 | 3.64 | 0.24 | 3.70 | 0.69 |
| 4/95 | 3.18 | 0.94 | 2.86 | 0.53 |
| 5/95 |  |  | 3.33 | 0.47 |
| 6195 | 3.90 | 0.79 | 3.13 | 0.31 |
| 7/95 | 3.89 | 0.69 | 3.88 | 0.80 |
| 8/95 | 4.17 | 0.86 | 3.25 | 0.59 |
| 9/95 | 3.38 | 0.55 | 3.12 | 1.44 |
| 10/95 | 3.32 | 0.44 | 2.87 | 0.76 |
| 11/95 | 3.08 | 0.37 | 2.91 | 0.53 |
| 12/95 | 3.41 | 0.47 | 2.68 | 0.31 |
| 1/96 | 3.32 | 0.61 | 2.76 | 0.43 |
| 2/96 | 3.73 | 0.58 | 3.05 | 0.41 |
| 3/96 | 3.93 | 0.38 | 3.07 | 0.39 |
| 4196 | 3.80 | 0.35 | 3.41 | 0.59 |
| 5/96 | 4.10 | 1.15 | 2.92 | 0.47 |
| 6/96 | 3.62 | 0.93 | 2.89 | 0.46 |
| 7/96 | 3.76 | 0.96 | 2.93 | 0.63 |
| 8/96 | 3.50 | 0.63 | 2.84 | 0.54 |
| 9/96 | 2.94 | 0.44 | 2.07 | 0.40 |
| 10/96 | 3.62 | 0.87 | 2.56 | 0.56 |
| 11/96 | 3.76 | 0.57 | 2.51 | 0.28 |
| 12/96 | 3.65 | 0.49 | 2.37 | 0.22 |

1. Standard deviation of monthly average.

**FIGURE 5.8.1-1**
**$NO_X$ EMISSIONS – UNIT 1**
**1992-1996**

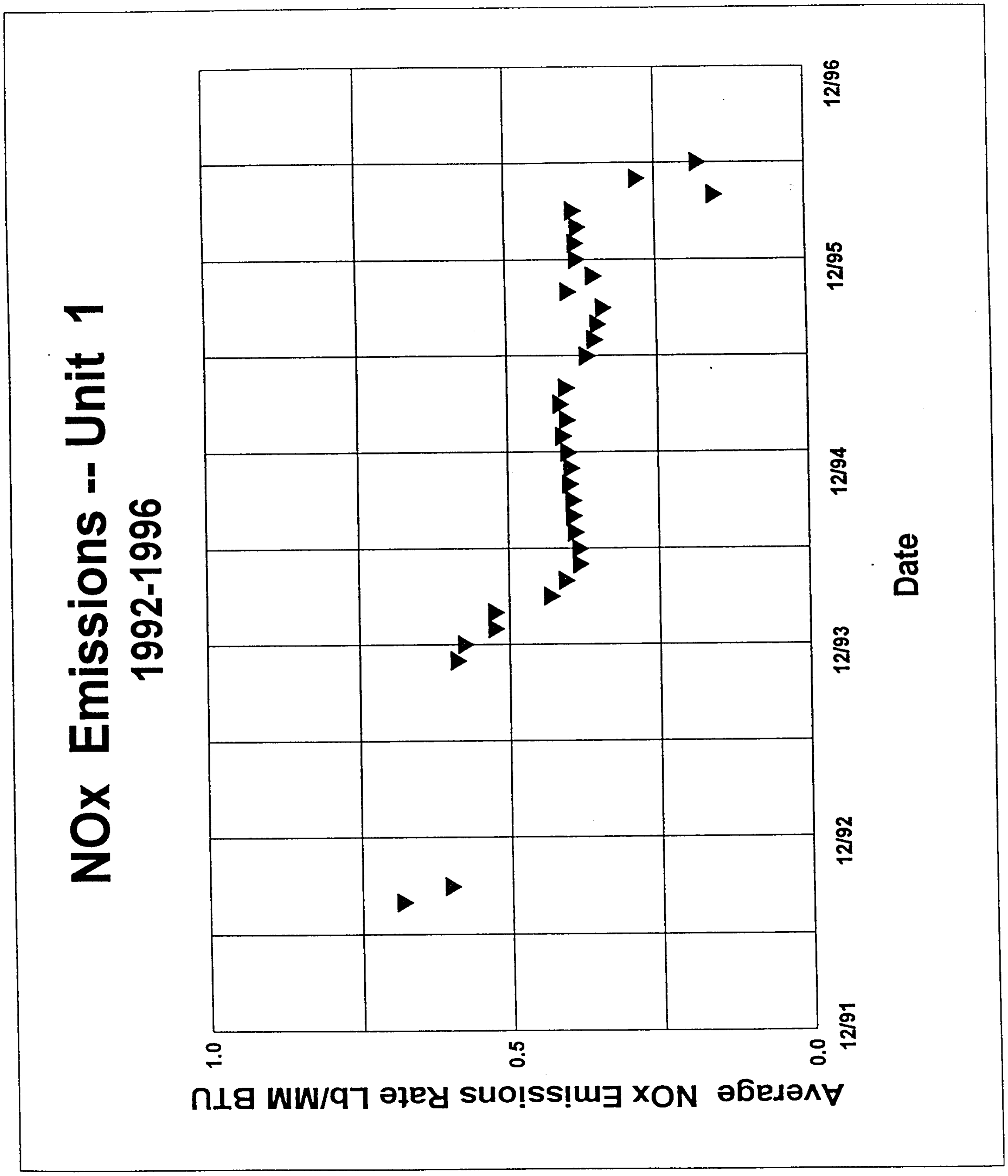


**FIGURE 5.8.1-2**
**NO$_X$ EMISSIONS – UNIT 2**
**1992-1996**

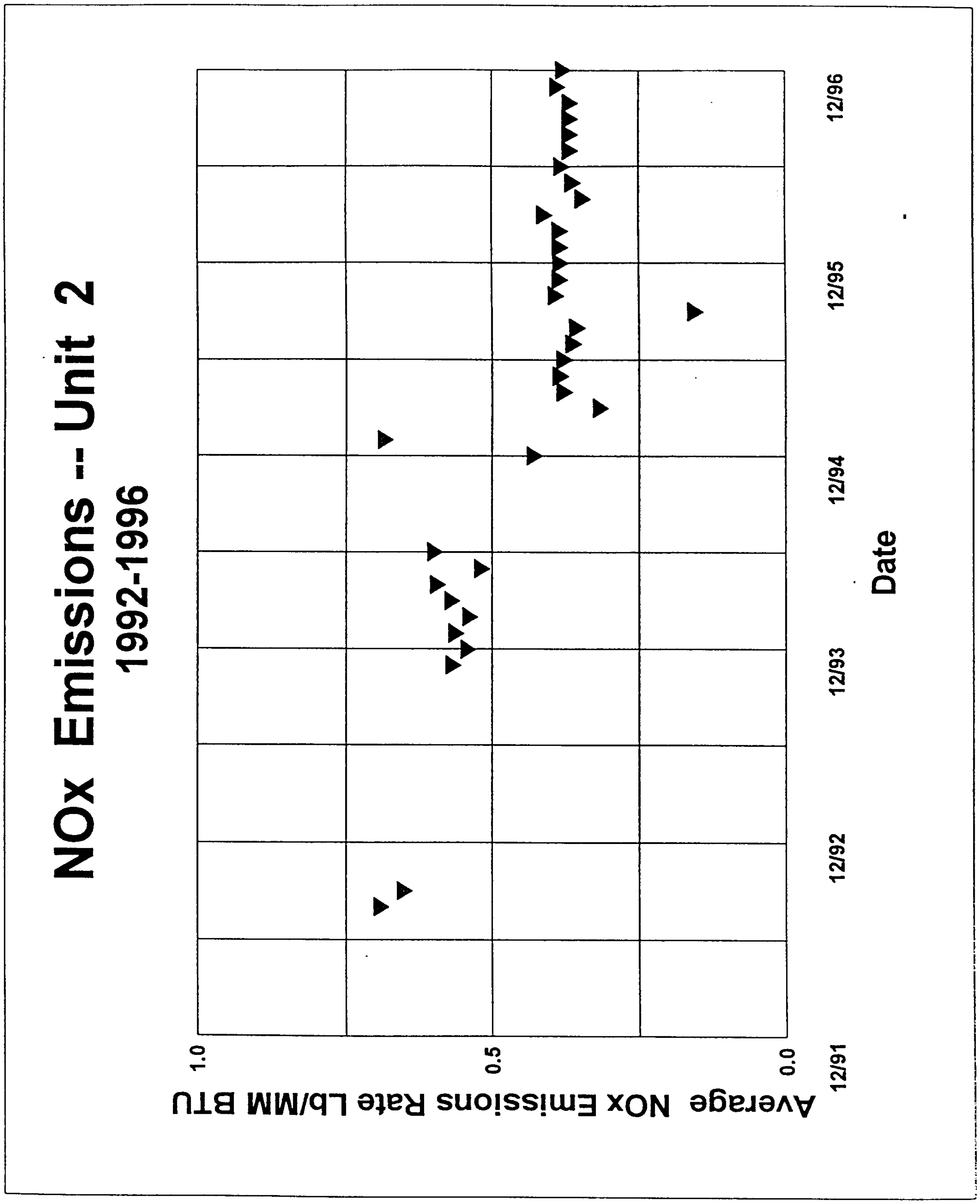
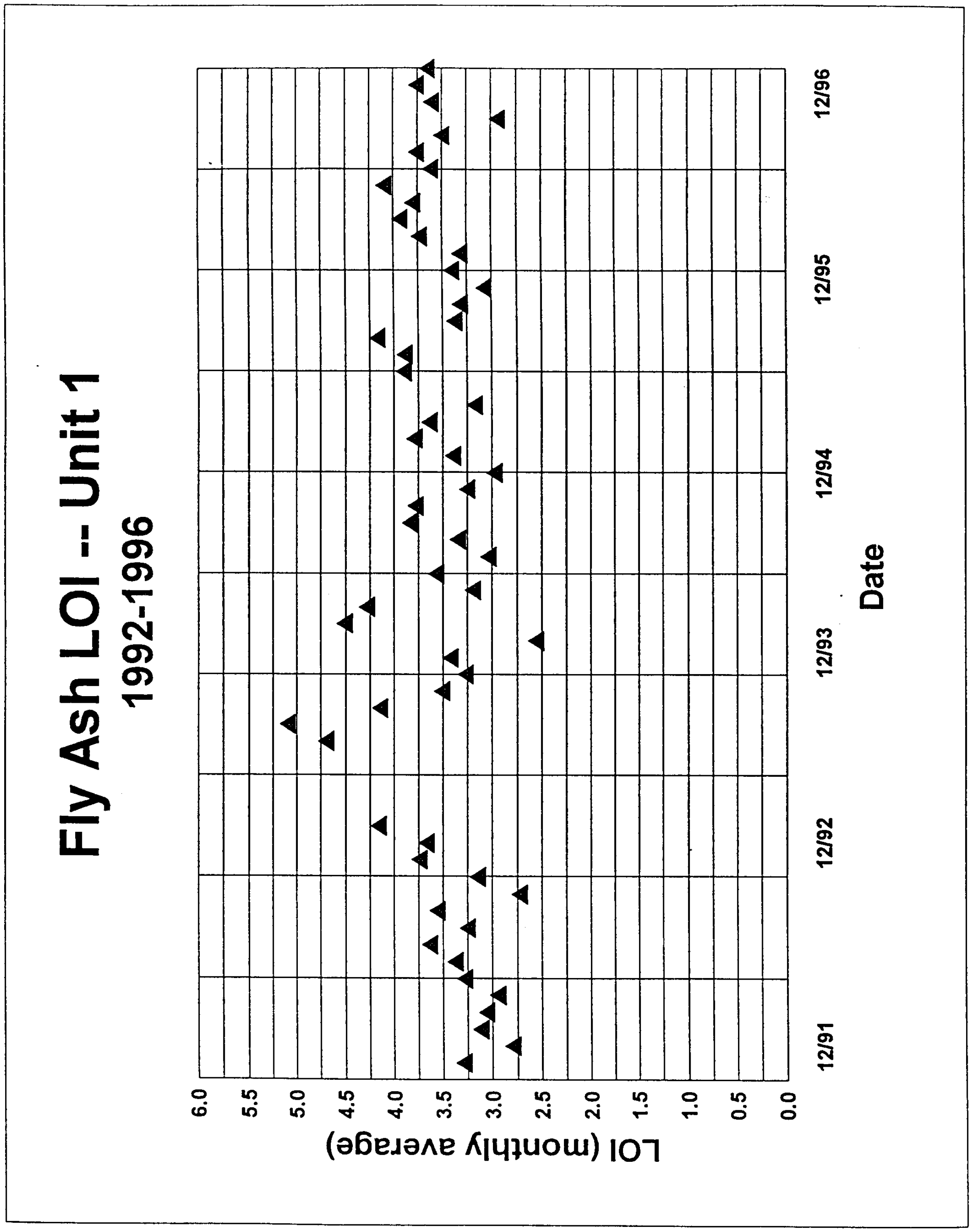
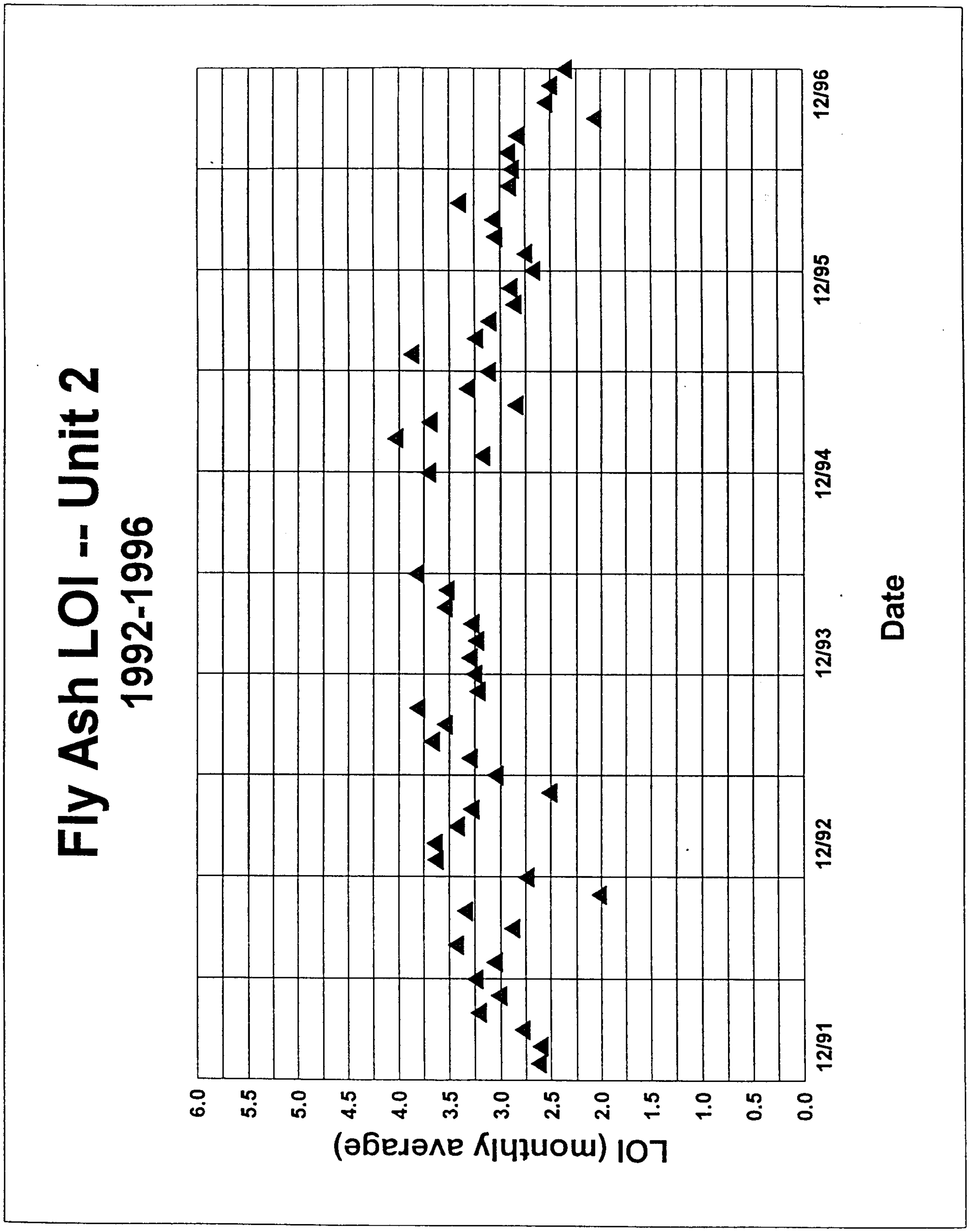


**FIGURE 5.8.1-3**
**FLY ASH LOI – UNIT 1**
**1992-1996**



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



# APPENDIX A TO IMPACT OF LOW-NO$_X$ 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$_X$ burners was determined according to the ASTM C618 protocols. The objective was to determine the impact of the low NO$_X$ 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$_X$ 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$_X$ burners, yet it remained well within the ASTM specification of 6% maximum.

## INTRODUCTION

Low NO$_X$ burners are the technology of choice to meet the Title IV utility NO$_X$ emissions limits under the Clean Air Act Amendments of 1990. However, conversion to low NO$_X$ 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$_X$ 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$_X$ 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$_X$ 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 $NO_X$ burners are within the requirements of ASTM C618 for use as a mineral admixture in Portland cement concrete. The two fly ashes have similar $SiO_2$, $Al_2O_3$, and $Fe_2O_3$ 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 $SO_3$ contents (0.83% and 0.93%) and moisture contents (0.19% and 0.16%), which are well below the maximum limits (5.0% $SO_3$ 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 $NO_X$ 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 $Na_2O$), 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 $NO_X$ 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 $NO_X$ 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** |
|---|---|---|---|
| CHEMICAL COMPOSITION, wt% | | | |
| Silicon Dioxide, $SiO_2$ | 48.43 | 47.52 | |
| Aluminum Oxide, $Al_2O_3$ | 23.50 | 23.45 | |
| Iron Oxide, $Fe_2O_3$ | 16.72 | 16.60 | - |
| Total, $SiO_2$ + $Al_20_3$**+** Fe2$O_3$ | 88.65 | 87.57 | 70.0 (Min) |
| Sulfur Trioxide, $SO_3$ | 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, $Na_2O$ | 0.44 | 0.68 | -- |
| Potassium Oxide, $K_2O$ | 1.79 | 1.71 | -- |
| Available Alkalies (as $Na_2O$) | 0.51 | 0.52 | 1.50 (Max) |
| PHYSICAL TEST RESULTS | | | |
| Fineness (c), % Retained on #325 Sieve | 12.15 | 8.51 | 34 (Max) |
| Strength Activity Index with Portland Cement, (d) | | | |
| 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, (d), % of Control | 93.1 | 91.3 | 105 (Max) |
| Soundness (e) (Autoclave Expansion), % | -0.051 | -0.051 | 0.8 (Max) |
| Drying Shrinkage, (f) | | | |
| Increase at 28 days, % | 0.008 | 0.005 | 0.03 (Max) |
| Specific Gravity (g) | 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 Cl09 and C311
(e) Determined in accordance with ASTM Methods C151 and C311
(f) Determined in accordance with ASTM Methods Cl57 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 $NO_X$ 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 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 $CaCl_2$ industry in North America, with a view towards identifying potential market opportunities for selling $CaCl_2$, which can be produced by upgrading FGD waste streams. The report begins with a section on the sources of $CaCl_2$ and production methods worldwide. It then describes in detail the major worldwide uses for $CaCl_2$, Next, the report gives the various product forms and specifications. The final section contains details on $CaCl_2$ consumption and pricing in North America. A copy of the full report can be obtained from DOE.

In 1992, U.S. $CaCl_2$ 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 $CaCl_2$ 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 $CaCl_2$ 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 $CaCl_2$ 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, $CaCl_2$ 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 $CaCl_2$ in North America is recovered from natural brines and salt deposits (54% of estimated current production capacity). The two other sources of $CaCl_2$, both synthetic, are a by-product of the Solvay process (29%), and from the neutralization of hydrochloric acid (17%). The only sources of $CaCl_2$ produced in the U.S. are via recovery from brines and from the neutralization of hydrochloric acid. $CaCl_2$ 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 $CaCl_2$ 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, $CaCl_2$ 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 $CaCl_2$ brine is mixed with rock salt and applied directly to the road surface. This combined mixture accelerates melting of snow and ice.

Solid $CaCl_2$ 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 $CaCl_2$ for these markets is often a brine, some of the $CaCl_2$ sold to these markets is as a solid in order to reduce transportation expenses.

$CaCl_2$ 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 $CaCl_2$. 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 $CaCl_2$ sold is marketed through this network of distributors.

$CaCl_2$ 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 $CaCl_2$ brine, and the limited capacity to produce $CaCl_2$ 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 $CaCl_2$ to identify and pursue these markets.

The most likely customers for the quantities of $CaCl_2$ 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 $CaCl_2$ and/or individual consumers of large quantities of $CaCl_2$. 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 $CaCl_2$ 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 $CaCl_2$ 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 $CaCl_2$ in the United States (as opposed to incurring the cost of disposal).
- At a minimum, utilities should plan to produce $CaCl_2$ brines which are at least 32% $CaCl_2$ 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.
- $CaCl_2$ 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%,
- $CaCl_2$ is an undifferentiated commodity chemical with well-established, mature markets. The principal uses/markets for $CaCl_2$ 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.

- $CaCl_2$ is also produced in Europe and Asia for similar uses/markets as those in the United States and North America.

- Much of the $CaCl_2$ sold is in the form of 32%-38% brine, which is prohibitively expensive to transport over extended distances. Thus, while excess $CaCl_2$ production capacity does exist, utilities can capitalize on niche market opportunities if they produce by-product $CaCl_2$ 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 $CaCl_2$, as well as the network of distributors (which is the way that most $CaCl_2$ is sold).

- If a utility is considering installing an FGD process and associated equipment to generate by-product $CaCl_2$ 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 imported into the United States, primarily from Canada (69%), Mexico (23%) and Spain (7%). Total by-product (chemical) gypsum production in the United States was estimated at 0.72 million short tons in 1992. In the United States, the largest consumer of gypsum is the wallboard industry (~75%), followed by the Portland cement industry (~15%), agricultural applications (~6%) and plaster manufacture (~4%). In 1992, total consumption of all gypsum in North America was approximately 26 million short tons. It was estimated that of this total, 20.5 million short tons was calcined for gypsum products while the remainder (5.5 million short tons) was used as a retardant in cement or as agricultural soil conditioner/supplement. Gypsum board companies own the majority of mines in the United States and supply their own plants with raw material. The gypsum rock (calcium sulfate dihydrate, $CaSO_4{\bullet}2H_2O$) is crushed, ground, calcined to the hemihydrate ($CaSO_4{\bullet}1/2H_2O$) and then formulated into a slurry with a number of other additives including starch, foam, accelerators/retarders and sometimes fillers. This slurry is cast between two sheets of paper and allowed to hydrate (harden) back to the dihydrate while traveling along the boardline. The boards are cut to the desired length and dried.

### Use of (FGD) Gypsum in Wallboard

Although the gypsum board manufacturing operation appears straightforward, the unit operations can be sensitive to changes in the raw materials. Therefore, direct substitution of synthetic gypsum for natural gypsum is not always possible. The characteristics of the feed material and its subsequent impact on the materials handling and process chemistry must be fully understood to facilitate by-product substitution.

Although the use of flue gas desulfurization (FGD) gypsum in wallboard manufacture is technically feasible by careful control of chlorides, particle size and moisture content (among others), utilization can be hindered by other factors, notably locality (in regard to added transportation costs) and the vertically integrated structure of the wallboard industry. Utilization potential is the highest in areas where the current market is being served primarily by imports (e.g., eastern United States seaboard), or where the distance between the mine and manufacturing site is large. One advantage of FGD gypsum is the typically high purity ($CaSO_4{\bullet}2H_2O$ content) which, when added as a portion of the board line feed, may improve some board properties with only minor changes to the operating parameters. FGD gypsum has been used successfully in the manufacture of wallboard in the United States and its use is continuing to grow.

### Utilization of FGD Gypsum in Portland Cement

Gypsum is used as an additive in Portland cement to control early setting properties, as well as to aid in grinding of the clinker. Crushed gypsum rock is inter-ground with the cement clinker at levels of 2-5%. As a result of this dilution factor, impurities within the gypsum are less of a concern than in applications where gypsum is the major component. Chloride levels however, are monitored because of associated corrosion in steel-reinforced concrete. The chloride specifications for gypsum used in cement are unclear, but are definitely less severe than those of gypsum for wallboard 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 EPRI 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 generically 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 $^{o}$F to 57 $^{o}$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 $1 \text{ X } 10^{-7}$ 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 | | | | | |
|---|---|---|---|---|---|---|
| | Queenston Shale [1] | Salt Spring [2] | Upgradient Well 9128D [3] | Leachate [4] | Seawater [5] | NY Class GA Standards |
| 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 pozzalonic reaction and is entrained with the intersticies 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.

## TABLE 5.9-2
## FLY ASH AND FGD SLUDGE ANALYSES 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 5.9-3
## HYDRAULIC CONDUCTIVITIES AND COMPRESSIVE STRENGTHS OF STABILIZED SLUDGE TEST MIXTURES USED DURING INITIAL DESIGN EVALUATION

| Ratio of Fly Ash to FGD Sludge (dry weight) | Hydraulic Conductivities (cm/sec) | | | Unconfined Compressive Strength (psi) 28 day cure |
|---|---|---|---|---|
| | 28 day cure | 60 day cure | 90 day cure | |
| 0.44/1.0 | 1.7 x 10$^{-6}$ | 0.7 x 10$^{-6}$ | 0.5 x10$^{-6}$ | 52 |
| 0.66/1.0 | 2.0 x 10$^{-6}$ | 1.2 x 10$^{-6}$ | 0.8 x 10$^{-6}$ | 60 |
| 1.0/1.0 | 1.2 x 10$^{-6}$ | 0.5 x 10$^{-6}$ | 0.5 x 10$^{-6}$ | 172 |
| 1.1411.0 | 0.5 x 10$^{-6}$ | N/A | N/A | 270 |
| 1.5/1.0 | 1.3 x 10$^{-6}$ | 1.1 x 10$^{-6}$ | 1.0 x 10$^{-6}$ | 315 |
| 2.0/1.0 | 1.9 X 10$^{-6}$ | 1.6 x 10$^{-6}$ | 1.0 x 10$^{-6}$ | 323 |
| 2.5/1.0 | 0.6 x 10$^{-6}$ | 1.4 x 10$^{-6}$ | 0.9 x 10$^{-6}$ | 352 |
| 3.0/1.0 | 0.6 x 10$^{-6}$ | 0.3 x 10$^{-6}$ | 0.1 X 10$^{-6}$ | 415 |
| 4.0/1.0 | 1.5 x 10$^{-6}$ | 1.3 x 10$^{-6}$ | 0.6 x 10$^{-6}$ | 555 |

N/A - Not Analyzed

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

Test mixtures were cured for 28, 60 and 90 days at 73 $^{O}$F and 95% humidity to simulate conditions within the landfill. The curing periods were selected to provide data on the 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 $^{O}$F due to the exothermic pozzolanic reaction. Temperatures on the outer edges of the fill may be lower than 40 $^{O}$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 | $5.62 \times 10^{-5}$ - $4.76 \times 10^{-6}$ | 54.6 - 168.9 |
| 1992 | $5.84 \times 10^{-5}$ - $1.53 \times 10^{-6}$ | 104.6 - 268.7 |
| 1993 | $7.25 \times 10^{-5}$ - $1.43 \times 10^{-6}$ | 53.2 - 287.4 |
| 1994 | $4.40 \times 10^{-5}$ - $2.97 \times 10^{-6}$ | 31.7 - 272 |
| 1995 | $9.20 \times 10^{-5}$ - $1.01 \times 10^{-6}$ | 12.4 - 27.1[1] |
| 1996 | $1.00 \times 10^{-5}$ - $2.90 \times 10^{-6}$ | 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 |
| OTHER CHARACTERISTICS | | | | |
| 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[1] (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 x $10^{-6}$ cm/sec has a theoretical leakage rate of 1.0 $ft^3$/year (7.5 gals/$ft^2$/year) versus a 5-foot natural soil liner with a k = 1.0 X $10^{-5}$ cm/sec which has a theoretical leakage rate of 40 $ft^3$/year (300 gal/$ft^2$/year). Even reducing the permeability of the 5-foot liner to 1.0 x $10^{-6}$ cm/sec, the flow rate is still 30 gal/$ft^2$/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 x $10^{-6}$ 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 x 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 Pirnie, 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 isotpes in the groundwater near Kintigue 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 | - | .1604 |
| Constant Dollars | - | .124 |
| O&M Cost Levelization Factor | | |
| Current Dollars | - | 1.293[1] |
| Constant Dollars | - | 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 |

---

[1] 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 indentified 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** | **$\$10^6$** | **$/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 |
| **A** | **Total Process Capital** | **53.7** | **179.0** |
| 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 |
| **E** | **Total Plant Cost (A+B+C+D)** | **65.0** | **216.5** |
| F | Allowance for Funds During Construction (1.9% of E) | 1.2 | 4.1 |

## TABLE 6.2-1

## TOTAL FGD SYSTEM CAPITAL REQUIREMENT
## 300 MW COMMERCIAL PLANT

| Area No. | Total Installed Equipment Cost | $\$10^6$ | $/kW |
|---|---|---|---|
| **G** | **Total Plant Investment (E+F)** | **66.2** | **220.7** |
| H | Royalty Allowance | | |
| I | Preproduction Costs | 2.3 | 7.7 |
| J | Inventory Capital | .51 | 1.7 |
| K | Initial Catalyst & Chemicals | | |
| **L** | **Subtotal Capital (G+H+I+J+K)** | **69.0** | **230.1** |
| M | Cost of Construction Downtime | 21.0 | 70.2 |
| **N** | **Total Capital Requirement (L+M)** | **90.0** | **300.3** |

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

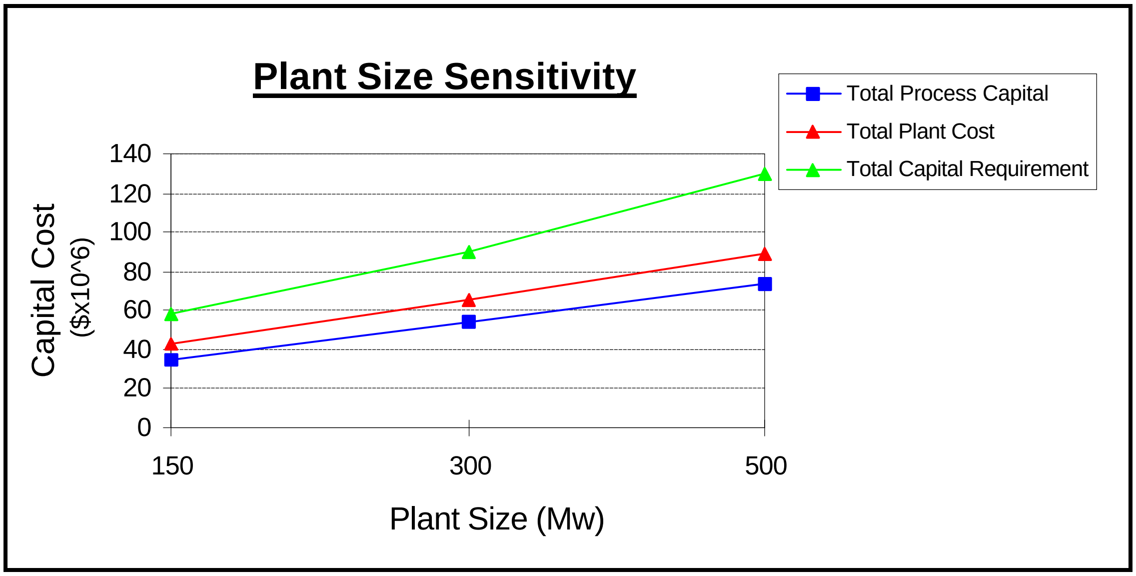
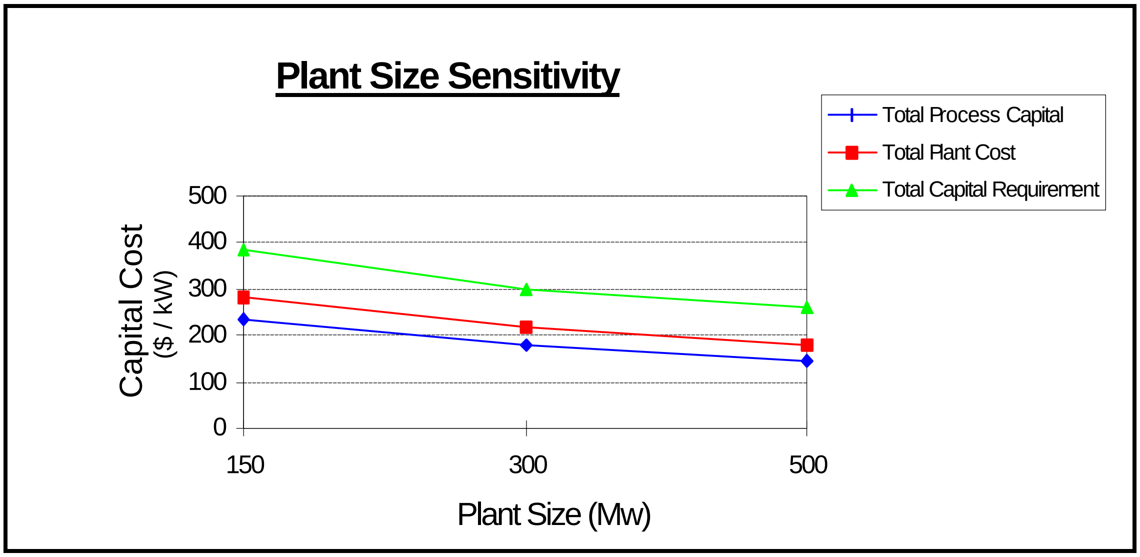


Figure 6.2-2



### 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** | **$10$^6$/YR** |
|---|---|---|---|---|
| Operating Labor | Man hr/hr | 26,280 | 23.00 | .6 |
| Maintenance Labor | | | | .26 |
| Maintenance Material | | | | .39 |
| Administration/Support Labor | | | | .26 |
| **Subtotal Fixed Costs** | | | | **1.51** |
| | | | | |
| **VARIABLE OPERATING COSTS** | | | | |
| 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 |
| **Subtotal Variable Cost** | | | | **3.11** |
| **TOTAL O&M COST (FIXED + VARIABLE)** | | | | **4.62** |

*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 $SO_2$ removed, divided by the amount of $SO_2$ 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 $SO_2$ 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 | $10^9$ kWh/yr | 1.708 |
| Capacity Factor | % | .65 |
| Plant Life | yr | 15 |
| Coal Feed | $10^6$ tons/yr | .629 |
| Sulfur In Coal | wt % | 3.2 |

| **Emissions Control Data** | **Units** | **$SO_2$** | **$NO_x$** | **TSP** | **$PM_{10}$** |
|---|---|---|---|---|---|
| Removal Efficiency | % | 95.0 | | | |
| Emissions Standard | lb/$10^6$ BTU | 1.20 | | | |
| Emissions Without Controls | lb/$10^6$ BTU | 5.01 | | | |
| Emissions With Control | lb/$10^6$ BTU | 0.25 | | | |
| Amount $SO_2$ 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 –$SO_2$ 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 –$SO_2$ + $NO_x$ 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 $SO_2$ removed on a current dollar basis, and \$413/ton $SO_2$ 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 $SO_2$ 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 $SO_2$ Removed | Plant Life | \$/Ton $SO_2$ Removed | Sulfur Content | \$/Ton $SO_2$ 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**

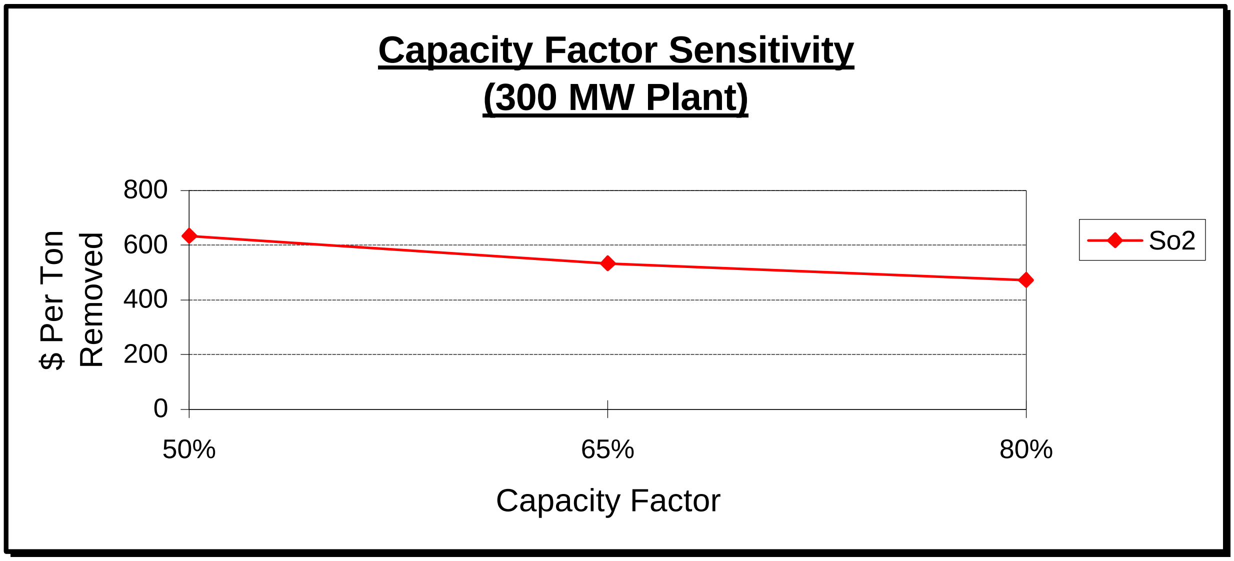


**Figure 6.5-2**

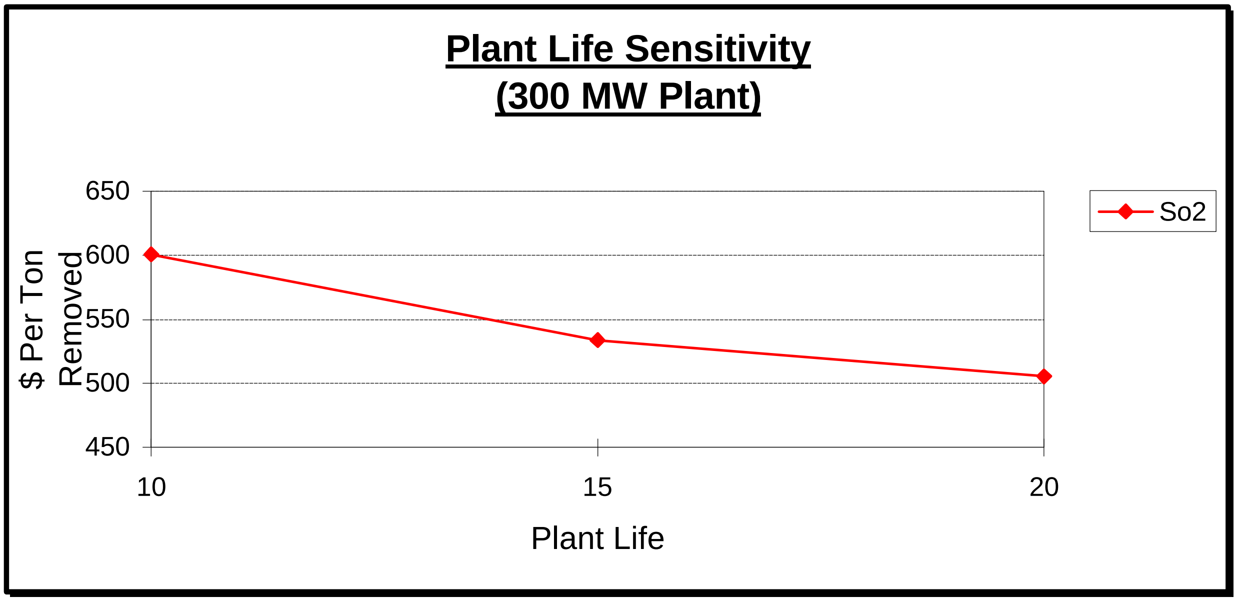
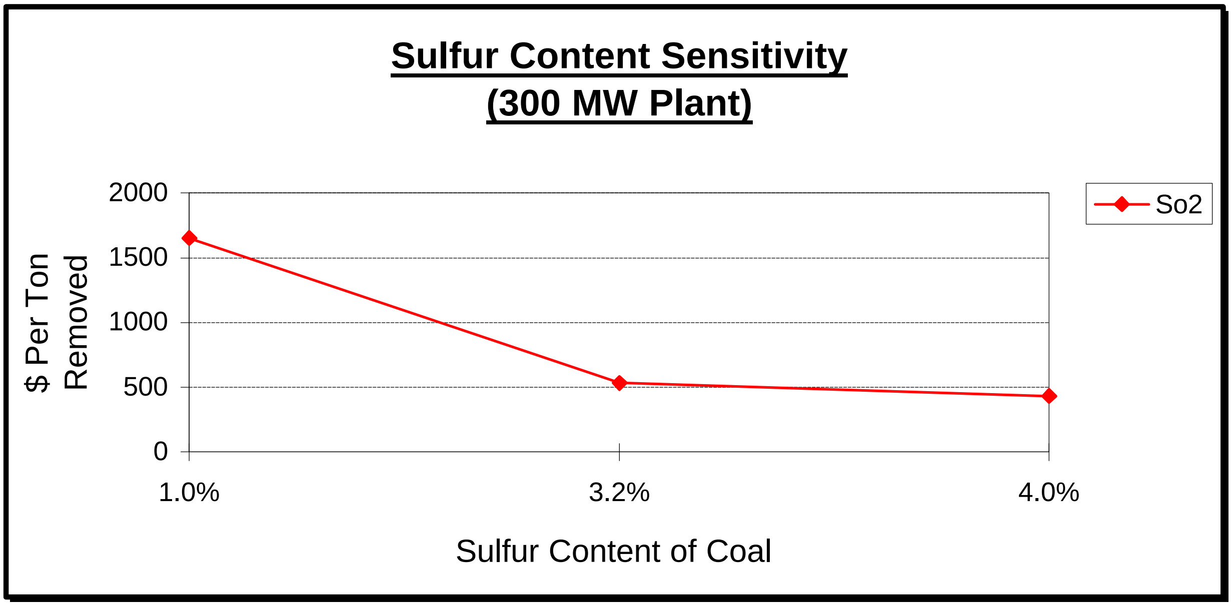


**Figure 6.5-3**



# 7.0 COMMERCIALIZATION 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 ($SO_2$) and nitrogen oxides ($NO_X$) 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 $NO_X$ mitigation upgrades to reach the levels of $SO_2$ and $NO_X$ required by legislation. In addition, the $SO_2$ emissions credit trading feature of the Clean Air Act Amendments places greater emphasis on ultra-high cost effective $SO_2$ removal capability. The ultra-high $SO_2$ removal capability of the SHU process, i.e., up to 98 percent $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ 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[a] 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% |

[a] 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[a] 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 levelized busbar costs and the total cost of $SO_2$ 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 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 NOx/SOx 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)

| | S-H-U FGD W/Tile Absorber | Pure Air Advanced FGD | LIFAC Sorbent Injection | AirPol Gas Suspension Absorber | Wet Limestone Forced Oxidation (Typical) | Confined Zone Dispersion |
|---|---|---|---|---|---|---|
| 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 | $144 | NA |
| **Total Capital Requirement ($/kW)** | **$300** | **$111** | **$66** | **$149** | **$216** | **$38** |
| **SO2 Removal Efficiency (%)** | **95%** | **90%** | **70%** | **90%** | **90%** | **50%** |
| Levelized busbar cost **(Current Mills/kWh)** | 11.96 | 8.65 | NA | 10.35 | 13.0 | NA |
| **Annual Levelized Cost (Current $/ton SO2 Removed):** | | | | | | |
| Capital Charge | $377 | $142 | NA | $291 | NA | NA |
| Fixed O&M | $51 | Included | NA | $129 | NA | NA |
| Variable O&M | $105 | $103 | $65 | $182 | NA | NA |
| Total | $533 | $245 | NA | $602 | NA | $384 |
| **Year of Costs** | **1995** | **1995** | **1993** | **1990** | **1990** | **1993** |
| **NOTES** | 1)Produces Salable Gypsum Product. | 1)Produces Salable Gypsum Product.<br>2)Capital Charge includes Fixed O&M Charges | | | 1)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 $SO_2$ allowance trading strategy. The market-based allowance trading system capitalizes on the power of the market to reduce SO2 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 reprised 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 $SO_2$, 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 $SO_2$ 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 $SO_2$. 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 SO2 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 SO2. 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 SO2 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 SO2 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 SO2. Formic acid is added to the slurry to buffer the solution and control the pH drop in the absorber, enhancing SO2 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 $SO_2$ 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 SO2 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 tranfer 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 $SO_2$ 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 $SO_2$ removal cost bases.

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

| | | | |
|---|---|---|---|
| | CAPITAL COSTS (market base) | | |
| | Plant Size (Mw) | 300.0 | |
| | Capacity Factor | 65.0% | |
| | | | |
| | FGD System Titles | $x1,000,000 | $/kW |
| | | | |
| 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 | So2 Removal System | 9.2 | 30.7 |
| 900 | NOx 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

| Fixed O & M Costs | Units | Quanity | $ / Unit | $(xM)/Yr |
|---|---|---|---|---|
| Operating Labor | Mnhr/hr | 27,040 | 23.00 | 0.62 |
| Maintenance Labor | | | | 0.18 |
| Maintenance Material | | | | 0.28 |
| Administration / Suppot Labor | | | | 0.24 |
| Subtotal Fixed Costs | | | | 1.33 |
| | | | | |
| Variable Operating Costs | | | | |
| 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 x10^3 | 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

| Power Plant Attributes | | | | Units | Value |
|---|---|---|---|---|---|
| Plant Capacity (net) | | | | Mwe | 300 |
| Power Produced (net) | | | | 10^9kWh/yr | 1.708 |
| Capacity Factor | | | | % | 65.0% |
| Plant Life | | | | yr | 15 |
| Coal Feed | | | | 10^6tons/yr | 0.629 |
| Sulfur in Coal | | | | wt % | 3.2% |
| | | | | | |
| Emissions Control Data | Units | SO2 | NOx | TSP | PM10 |
| Removal Efficiency | % | 95.0% | | | |
| Emissions Standard | lb/10^6BTU | 1.20 | | | |
| Emissions Without Controls | lb/10^6BTU | 5.01 | | | |
| Emissions With Controls | lb/10^6BTU | 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 | 7.53 | 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 - SO2 Basis | | Factor | $/ton Removed | Factor | $/ton Removed |
| 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 - 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 |

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 | | | | | | SO2 REMOVED | LEVELIZED COST OF POWER | | LEVELIZED COST - SO2 BASIS | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Process Capital | | Total Capital Requirement | | Fixed | Consumables | Electric Power | By-products | Waste Disposal | Total Fixed & Variable | Tons/yr | Current | Constant | Current | Constant |
| | $ x 1,000 | $ / KW | $ x 1,000 | $ / KW | $ x 1,000 | $ x 1,000 | $ x 1,000 | $ x 1,000 | $ x 1,000 | $ x 1,000 | | Mills/ kWh | Mills/ kWh | Mills/ kWh | 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 | 424.1 | 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

| Item | Approximate Size Ratio | Approximate Capital Savings |
|---|---|---|
| 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 Umweltttechnik 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.

## 7.2 STEBBINS ABSORBER

### MARKET ANALYSIS

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.

## APPLICABILITY OF THE TECHNOLOGY

Stebbins reinforced concrete/ceramic tile absorber module construction is applicable to the retrofit and grass roots wet lime and wet limestone utility and industrial FGD markets. Its life-cycle costs compare favorably with lined carbon steel and alloy construction, with which it would compete. The construction method is suitable for single or split absorber modules from less than 100 to greater than 500 MW equivalent, making it applicable to most, if not all, utility wet FGD retrofit and grass roots installations. The cocurrent/countercurrent, split module absorber configuration used by the MCCTD project is specific to the SHU FGD process. The reinforced concrete/ceramic tile construction offered by Stebbins is suitable as an alternative to lined carbon steel or alloy construction for any of the free-standing absorber configurations currently on the market. This construction can be used for countercurrent cylindrical or rectangular, open spray, tray, or packed towers. This construction is extremely versatile; its inherent benefits are available regardless of the specific absorber module configuration employed. 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 used at Milliken. 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. Stebbins tile can be applied on many base materials, including carbon steel. The MCCTD project should provide a base to market the tile in new FGD applications and as a corrective alternative for existing FGD modules and subcomponent liners in need of maintenance upgrade.

## MARKET SIZE

A fully detailed analysis of the potential market for Stebbins tile absorbers is provided in Volume I of the *Public Design Report*. The results of this analysis are summarized in table 7.2-1. In this analysis the total U.S. electric market available to the Stebbins tile absorbers was assumed to be the same as that for the SHU FGD technology. As for the SHU process, the market 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 $SO_2$ 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 market penetration for Stebbins tile was assessed in a similar fashion to that of the SHU process. Table 7.2-1 shows the share of the FGD absorber market that the Stebbins tile absorber construction 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 Stebbins absorber 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 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.

### TABLE 7.2-1
### ESTIMATED STEBBINS TILE FGD ABSORBER MARKET SHARE

| Year | Five Year Avg. share |
|---|---|
| 1996-2000 | 0.019 |
| 2001-2005 | 0.029 |
| 2006-2010 | 0.044 |
| 2011-2015 | 0.065 |
| 2016-2020 | 0.097 |
| 2021-2025 | 0.143 |
| 2026-2030 | 0.237 |

## MARKET BARRIERS

The major technical risk associated with employing the Stebbins' tile/reinforced concrete design concerns potential corrosion of the concrete and rebar, due to leakage through cracks in the tiles or deteriorated mortar. To handle leaks, Stebbins has devised a repair method based on visual detection of a leak, drilling a hole from outside of the vessel, and pumping sealant through the hole to seal the leak. Since repairs to the external walls may be safely made while the unit is in operation, unscheduled shutdown for leaks should not be required. In addition, inspection and repointing, if necessary, of the mortar between the tiles will be performed during scheduled boiler outages. This repair method was demonstrated as part of the MCCTD project.

The concept of constructing an absorber module below the flues has not been demonstrated in the U.S., although this concept has been demonstrated in Austria. The proposed demonstration project differs from the Austrian unit in several significant areas. The MCCTD project uses multiple stack flues, a rectangular absorber base, a wet stack, and up to 4% sulfur coal and has a total capacity of 300 MWe. The Austrian unit has a single flue, a circular absorber base, flue gas reheat, burns low-sulfur coal, and has a total capacity of 220 MWe. None of these differences resulted in significant design or operational problems.

Another potential problem was the possible accumulation on the inner surface of the stack flue of significant amounts of solids, which could break off and fall back into the absorber module and cause damage to its internals. The degree of buildup would be a function of process chemistry, process design, and mist eliminator performance. If solids buildup were to be a problem, it should appear during the demonstration run. However, with the advanced FGD process design provided by SHU, mist carryover was low enough so that significant flue liner solids buildup did not occur.

## ECONOMIC COMPARISONS WITH COMPETING TECHNOLOGIES

Because of its resistance to chemical attack and its ease of repair, the reliability of the Stebbins tile and mortar system is superior to any other material for absorber construction. Also, lifecycle costs are substantially lower than those of either a steel alloy absorber or a carbon steel absorber lined with chlorobutyl rubber or flake glass. 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.

Conventional absorbers are usually made of carbon steel plate lined with a variety of different organic and inorganic materials. Some competing absorber liner technologies are listed in Table 7.2-2. Stebbins tile lining will be cost competitive with these other available lining materials and technologies.

### TABLE 7.2-2
### COMPETING ABSORBER LINER TECHNOLOGIES

- Organic Liners
  - Natural (gum) rubber
  - Neoprene
  - Glass flake-filled/Mica flake filled/Glass Cloth or Glass mat reinforced
    - Polyester resin
    - Chlorinated polyester resin
    - Epoxy resin
    - Vinyl ester resin
  - Fluorelastomer
  - Epoxy
  - Coal Tar Epoxy
  - Urethane
  - Urethane-asphalt
  - Chlorobutyl Rubber
  - Self-Vulcanizing Butyl Rubber
- Inorganic Liners
  - Calcium Alumina Silicate
  - Potassium Silicate
  - Pre-krete
- Metallic Liners
  - Numerous High Nickel Alloys

Stebbins tile absorbers have a number of innate competitive advantages. This tile system is amenable to a wide range of FGD systems, and not just limited to the SHU process. Maintenance during outages is lessened with Stebbins tile absorbers compared to other types of absorber construction. This is because of the superior low-maintenance characteristics afforded by the structural and mechanical properties of 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**

The following absorber plate (with stiffeners) cost comparisons are based on a 0.25 inch thick plate and knockdown construction. *****

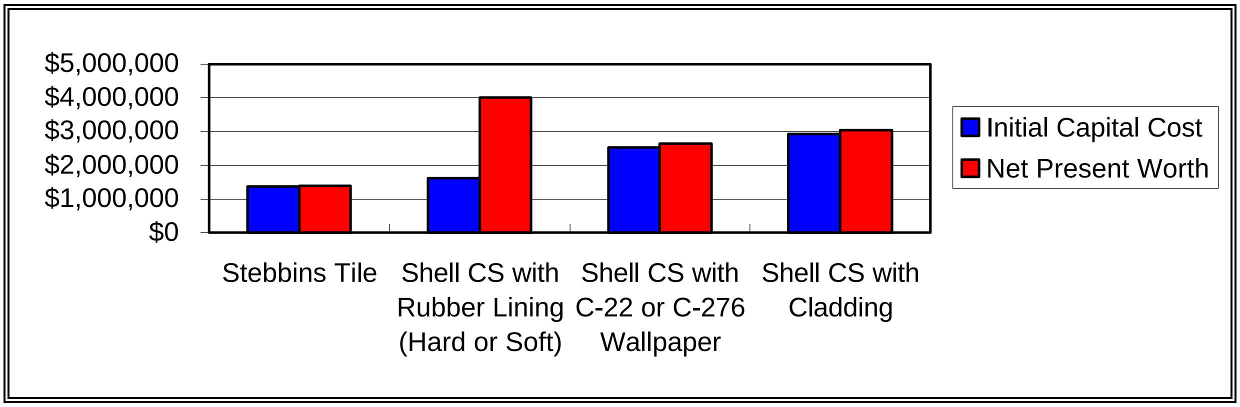
| | 1997 | | |
|---|---|---|---|
| **Material**** | **Procurement/ Fabrication** | **Erection** | **Total** |
| Stebbins Tile | $1,374,000 | Included | $1,374,000 |
| Shell CS with Rubber Lining (Hard or Soft) | $1,603,000 | Included | $1,603,000 |
| Shell CS with C-22 or C-276 Wallpaper | $2,519,000 | 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 $20^{o}$ 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 $25^{o}$ F (from $280^{o}$ F to $255^{o}$ 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 is 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 7.3-1shows 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 $SO_3$ 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 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 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 napthalene 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 $10^6$)

| | **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

| | Primary Air | | | | | | Secondary Air | | | | | | Flue Gas | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alternative | head inwc | flow, #/hr | Temp, °F | density, #/ft3 | Flow, ACFM | Air HP | head inwc | flow, #/hr | Temp, °F | density, #/ft3 | Flow, ACFM | Air HP | head inwc | flow, #/hr | Temp, °F | density, #/ft3 | 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 | 278 | 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/ESEERCO 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[1] | 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[3] | 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;<br>HR, Emissions & Steam Cycle Mods under Development | Monitor + Advisor Available;<br>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;<br>$ 230K Closed Loop | $ 180K Supv;<br>$ 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[2] | 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[4] | 7[4] | 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ into harmless nitrogen, carbon dioxide, and water. The urea/$NO_X$ reaction takes place only in a narrow temperature range, 1600 $^oF$ to 2100 $^oF$, below which ammonia is formed and above which $NO_X$ 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 $NO_X$ to be removed in stages, with a portion of the required $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$. NOxOUT® used in this fashion is expected to reduce $NO_X$ 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 $NO_X$ 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 $NO_X$ reduction and the NOxOUT® process to demonstrate its $NO_X$ removal capabilities. The NOxOUT® demonstration was intended to show that $NO_X$ 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 $NO_X$ 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 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 $NO_X$ 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 $NO_X$ emission reduction, depending on boiler temperature profile and $NO_X$ inlet loading, among other factors, using urea as the reactant chemical. Urea decomposes into ammonia and reacts with the $NO_X$ to produce nitrogen, carbon dioxide and water. The method of $NO_X$ removal is to inject the urea-based solution into the gas stream. The nitrogenous species in the solution react with the $NO_X$ 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 $NH_3$ 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, $NO_X$ emission reduction is in the range of 25 to 45 percent, depending on various factors which include:

- Inlet $NO_X$ 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 $NO_X$ 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 $NO_X$ levels (e.g., > 300 ppm)

Because the size of the boiler is a significant factor in achieving good chemical mixing and dispersion, lower $NO_X$ 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 $NO_X$ loading, $NO_X$ 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 $NO_X$ 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 $NH_3$ levels exceed 5 ppm. These deposits typically occur in the intermediate temperature baskets of the air preheater. Plume opacity problems can arise with higher $NH_3$ slip levels and high concentrations of either $SO_2$ 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 $NH_3$ 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 $NO_X$. Conversely, if the temperature window occurs in the convective section, $NO_X$ 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 $NO_X$ 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.
- $NO_X$ reductions are comparable using urea or ammonia based chemicals, although the limited available data suggest that ammonia slip is lower with ammonia based chemicals.
- $N_2O$ emissions are higher with urea (10-40 percent of the $NO_X$ reduced) than with ammonia (less than 5 percent of the $NO_X$ 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 $NH_3$ emissions. The trend is to lower $NH_3$ slip, and where limits do not presently exist, it is likely that they will in the near future. Lower $NH_3$ slip will tend to lower the $NO_X$ 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 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.

## ECONOMIC COMPARISONS WITH COMPETING TECHNOLOGIES

As a stand-alone technology, the NOxOUT® process could have the lowest cost per ton of $NO_X$ removed when the consequences of other technologies are considered.

The use of combustion modifications alone for $NO_X$ emissions reduction, either over-fired air ports or low $NO_X$ burners, has several operational and economic disadvantages compared to their use in combination with a $NO_X$ 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 $NO_X$ 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 $NO_X$ reductions achieved by combustion modification to a level consistent with fly ash sales and use the NOxOUT® process to trim the $NO_X$ 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 $NO_x$ 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 $^oF$ 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 $NO_X$ 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, $NO_X$ could be increased. The combination of NOxOUT® with combustion technologies will allow higher combustion oxygen levels and hence better boiler performance while maintaining $NO_X$ 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 $NO_X$ 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 $NO_X$ removal technology with reduced risk of losing the boiler flame or "puffing" the boiler.

Selective Catalytic Reduction (SCR) is the other $NO_X$ removal technology that would be considered for large scale $NO_X$ 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$^{O}$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 $NO_X$ 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.

$NO_X$ 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® $NO_X$ abatement systems.

# 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 $NO_x$, $SO_2$, $O_2$, CO, $CO_2$, 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.

Phase1: 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 (FTPA™) and Plant Economic Optimization Advisor (PEOA™). This product line is currently licensed to DHR under a NYSEG License Agreement dated February 19, 1997. 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

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:

<u>Five (5) Year Sales Goals</u>

| | |
|---|---:|
| • 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 $NO_X$ 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 $NO_X$ 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 ($CO_2$, CO, $SO_2$, $NO_X$, $O_2$), 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-$NO_X$ 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 $NO_X$ 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 $NO_X$ emissions control strategy included combustion modifications to minimize $NO_X$ emissions and simultaneously optimize boiler thermal efficiency. NYSEG installed Low-$NO_X$ Concentric Firing System (LNCFS) burners. The burners are controlled by the boiler control system to optimize combustion efficiency while minimizing $NO_X$ emissions.

The objective of the LNCFS-3 evaluation program was to supplement and confirm earlier demonstrations of the LNCFS-3 low $NO_X$ 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-$NO_X$ Concentric Firing System Level 3 (LNCFS-3) burner retrofit in reducing $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ 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-$NO_X$ burner retrofit was adopted. Unit 2 retrofit was scheduled approximately one year after that of Unit 1. A comparison of Units 1 and 2 $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ emissions.

At full boiler load (145-150 MW) and 3.0%-3.5% economizer $O_2$, the LNCFS-3 burner lowered $NO_X$ 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 $O_2$ the LNCFS-3 burner lowered $NO_X$ 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 $O_2$ 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 $O_2$, coal air flow, burner tilt, and reduced load mill patterns on $NO_X$ emissions and LOI. The following conclusions were reached:

- Both $NO_x$ and LOI results showed good reproducibility. Uncertainties at 95% confidence were ± 0.016 lb $NO_x$/MM Btu and ± 0.30% LOI. $NO_2$ was not measured, and reported $NO_X$ measurements were the sum of both NO and $NO_2$.

- Changing fuel air damper position had a significant effect on LOI and a minor effect on $NO_X$ 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 $NO_X$ emissions, but not LOI. Changing burner tilt from $\pm 15^o$ to $0^o$ increased $NO_X$ emissions by 0.04 lb/MM Btu.

- At reduced boiler loads (110 MW and lower), taking the top burner elevation out of service reduced $NO_X$ emissions, but made it difficult to maintain steam temperatures.

- Higher excess $O_2$ levels (measured at economizer outlet) increased $NO_X$ emissions and reduced LOI. The results showed that the impact of excess air on $NO_X$ emissions was reduced at lower boiler loads.

- Higher boiler loads increased $NO_X$ emissions and reduced LOI at the same excess $O_2$ level.

- Lower $NO_X$ emissions corresponded to higher LOI. Predictive correlations for $NO_X$ emissions and LOI were derived:

  $$1b\ NO_x\ /MM\ Btu = 0.34 - 0.036*02 + 0.0009*MW*O_2 - 0.00017*(TILT)^2 \qquad r^2 = 91\%$$

  $$\%\ LOI = -1.2 + 9.4/O_2 + 0.25*AIR - 0.024*(MW-140) \qquad r^2 = 84\%$$

  where
  $O_2$ is excess $O_2$ 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 $NO_X$ 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 $O_2$, 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 $NO_X$ emissions and LOI. The following conclusions were reached:

- The post-retrofit tests had a greater level of uncertainty in $NO_X$ emissions and about the same level of uncertainty in LOI, compared to the baseline tests, Uncertainties at 95% confidence were ± 0.027 lb $NO_X$ /MM Btu and ± 0.35% LOI.

- Gas stratification across the two ducts at the economizer outlet was minor.

- $NO_2$ 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 ($0^o$) was estimated to reduce $NO_X$ 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 $NO_X$ emissions or LOI. SOFA yaw changes (relative to the fuel firing angle) did not significantly change $NO_X$ 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 $NO_X$ emissions and increased LOI. Changes in SOFA damper position had a greater effect on $NO_X$ 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 $NO_X$ emissions and LOI, but the effect was greater on $NO_X$ emissions.

- Higher excess $O_2$ increased $NO_X$ emissions and reduced LOI.

- In general, higher boiler loads increased both $NO_X$ emissions and LOI.

- Higher mill classifier speeds reduced both $NO_X$ emissions and LOI, but the effect on LOI was more dramatic.

- The post-retrofit relationship between $NO_X$ and LOI was more complex than the pre-retrofit relationship because of greater sensitivity of the low $NO_X$ 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 $NO_X$ emissions.

- Predictive correlations for $NO_x$ emissions and LOI were derived:

$$\text{lb } NO_X \text{ /MM Btu} = 0.12 + 0.08{*}O_2 + 0.00003{*}(MW-120)^2 -$$

$$(RPM-93) + 0.007{*}TILT \qquad\qquad r^2 = 84\%$$

$$\%\ LOI = 8.1 - 1.08{*}O_2 + 0.032{*}(MW-120) -$$

$$(RPM-93) + 0.155{*}TILT \qquad\qquad r^2 = 69\%$$

  where
  $O_2$ is excess $O_2$ 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 $NO_X$ emissions could potentially be reduced to about 0.35 lb/MM Btu at full boiler load, while maintaining salable fly ash.

- The low $NO_X$ burner retrofit reduced $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ and CO emissions, fly ash LOI and boiler efficiency.

The achievable annual $NO_X$ emissions were estimated using long-term (60-70 days) CEM measurements. The achievable annual $NO_X$ 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 $NO_X$ emissions for Unit 2 baseline were 0.614 lb/MM Btu, with a 95% confidence level of ± 0.023 lb/MM Btu.

- The achievable annual $NO_X$ emissions for Unit 1 LNCFS-3 were 0.390 lb/MM Btu, with a 95% confidence level of ± 0.003 lb/MM Btu. That corresponded to 134 MW boiler load and 3.72% $O_2$ at the economizer outlet. The LNCFS-3 burner system achieved 36% $NO_x$ reduction. However, direct comparison of baseline and post-retrofit $NO_X$ emissions can be misleading, since the corresponding economizer $O_2$ 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 $NO_X$ 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 $O_2$ and boiler load. The test parameters for Unit 1 LNCFS-3 were economizer $O_2$, coal fineness and boiler load. The following conclusions were reached:

- For Unit 2 baseline, satisfactory predictions were obtained for both $NO_X$ 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 $NO_X$ /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 $NO_X$ emissions at full boiler load (145-150 MW).However, predictions for $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ emissions, boiler efficiency, fly ash LOI and CO emissions. Specifically:

- At full boiler load (145-150 MW) and 3.0%-3.5% economizer $O_2$, the LNCFS-3 system lowered $NO_X$ 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 $O_2$, the LNCFS-3 system lowered $NO_X$ 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 $O_2$ 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 $NO_x$ emissions beyond that achievable by combustion modifications alone. Nalco'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 $NO_X$ emissions by more that 30% in addition to the reductions achieved by combustion modifications. Project goals included:

- Demonstration of additional $NO_X$ reductions beyond the reductions achieved by combustion modifications;

- Minimal ammonia ($NH_3$) 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, $CaCl_2$.

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 $NO_X$ achievable, (2) short-term $NO_X$ emissions, (3) 30-day rolling average $NO_X$ emissions, and (4) annual $NO_X$ 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. $NO_X$, $O_2$ 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 $NH_3$ 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 $NO_X$ 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 $^{o}$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 $NO_x$ 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 | Upper ESP | New ESP |
|---|---|---|---|
| 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, $ft^2$/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 $ft^2$ 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 ($SO_2$)
- Sulfuric Acid Mist ($SO_3$)
- Particle Size Distribution
- Flue Gas Composition ($O_2$, $CO_2$, $N_2$, and $H_2O$)
- 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$^{TM}$.

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:

Penetration = 100% - 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

| | 17-Apr-94 | | 18-Apr-94 | | 19-apr-94 | |
|---|---|---|---|---|---|---|
| TR-Set Designation | 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)**

| | 17-Oct-95 | | 18-Oct-95 | | 19-Oct-95 | | 20-Oct-95 | |
|---|---|---|---|---|---|---|---|---|
| TR-Set Designation | 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 $ft^2$ 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 ($O_2$ and $H_2O$)
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 µm and minus 2.5 µm fractions. The minus 10 µm and minus 2.5 µm 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 µm and minus 2.5 µm 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 $SO_3$ 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 then 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 $SO_2$ removal, L/G ratio, pressure drop, formate loss, oxidation air utilization and gypsum and chloride brine quality.

The SHU technology was expected to reduce $SO_2$ emissions by at least 95%. Project goals included:

- Demonstration of up to 98% $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ and reduces the potential for scaling and plugging. This creates a stable system that can accommodate rapid changes in inlet $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ removal.
- To determine the effect of limestone grind size on $SO_2$ 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 $Cl^-$ 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 $SO_2$ 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 $S0_2$ 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 $SO_2$ 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:

### $SO_2$ Removal

- $SO_2$ 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 $SO_2$ 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).

- $SO_2$ 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, $SO_2$ removals increased with increasing L/G. When the results were separated based on the number of countercurrent headers operating a significant difference in $SO_2$ removals occurred for the same L/G depending upon the number of countercurrent headers in use. In general, the data show that more $SO_2$ removal is achieved when a higher percentage of the total slurry is sprayed in the countercurrent section.

- The effect of countercurrent L/G on $SO_2$ 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.

- $SO_2$ removal was increased significantly by formic acid. For example, using five spray headers, $SO_2$ removal averaged 82% without formic acid and 97% with 800 ppm formic acid. $SO_2$ 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 $SO_2$ 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 $SO_2$ removal.

- Nine tests were performed using an alternate limestone grind size. Higher $SO_2$ removal was observed using the finer grind (90%-325 mesh) limestone than with the coarser grind (90% - 170 mesh) limestone. The average difference in $SO_2$ removal between the two grind sizes was 2.6 percent (absolute). The effect was greatest at the intermediate formic acid concentration.

- $SO_2$ 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 $SO_2$ was removed during the high velocity tests than during the design velocity tests. For example, $SO_2$ 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 $SO_2$ concentration (due to coal sulfur variability) and the chloride content in the absorber slurry.

The inlet $SO_2$ concentration slowly decreased over the 42-day test period. During the tests without formic acid the inlet $SO_2$ averaged 1000 ppm; the average decreased to 970 ppm and 879 ppm $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 ±0.25 of the set point. For the design gas velocity tests the boiler load was 158 ±2.5 gross MWe, giving a absorber inlet gas flow of 490 ±8 kacfm. For the high velocity tests, the combined Unit 1 and Unit 2 boiler load was 213 ±11 gross MWe, giving a gas flow of 721 ±35 kacfm. The absorber inlet gas temperature averaged 298 $\pm 13^{o}$ F in the design velocity tests and 276 $\pm 7^{o}$ 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 $SO_2$ 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 $SO_2$ 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% $SO_2$ 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, $NO_X$ 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%. $SO_2$ 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 suctions. 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 $SO_2$ 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 $SO_2$ efficiency and gypsum quality, even higher $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 µm, as compared to the 20 µm 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 ($SO_2$) and nitrogen oxides ($NO_X$) 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 $NO_X$ mitigation upgrades to reach the levels of $SO_2$ and $NO_X$ required by legislation. In addition, the $SO_2$ emissions credit trading feature of the Clean Air Act Amendments places greater emphasis on ultra-high cost effective $SO_2$ removal capability. The ultra-high $SO_2$ removal capability of the SHU process, i.e., up to 98 percent $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ 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, $SO_2$ and NOx 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 $^0$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 $^0$F-18 $^0$F above the 253 $^0$F design temperature and for the 2B heat pipe was 12 $^0$F above the design. For the November 1996 performance tests, the differences were slightly higher at 20 $^0$F-23 $^0$F for the 2A heat pipe and 15 $^0$F - 16 $^0$F for the 2B heat pipe. Based on an analysis done by CONSOL R&D, the uncertainty in these results is ±4.4 $^0$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 $^0$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 Infrafone® 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 Infrafone® is a device which uses high intensity, ultra low frequency sound for on-line equipment cleaning. Neither the Infrafone® nor the modified sootblower lances appeared to provide any significant cold-end cleaning benefit over the existing sootblowers. The Infrafone® 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 $SO_3$ level to the heat pipe air heaters by injecting additives such as $Mg(OH)_2$ or MgO into the boiler. Reducing the flue gas $SO_3$ level would

decrease the acid dew point and allow lower temperature operation without condensation. This form of $SO_3$ 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-$NO_X$ 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 $NO_X$ Concentric Firing System Level 3 (LNCFS-3) burners to reduce $NO_X$ emissions while maintaining high combustion efficiency and acceptable fly ash loss on ignition (LOI). The achievable annual $NO_X$ 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 $NO_X$ 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 $SO_2$, $NO_2$, $O_3$, TSP and $PM_{10}$ 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 $SO_2$ levels showed a reduction by an average of 40-50% over the course of the 4-year air monitoring study. The ambient $NO_2$ levels also were reduced by an average of 10-15% at the North and South sites, while very little change was observed in the $NO_2$ 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 $PM_{10}$ ambient levels.

## SOLID WASTE

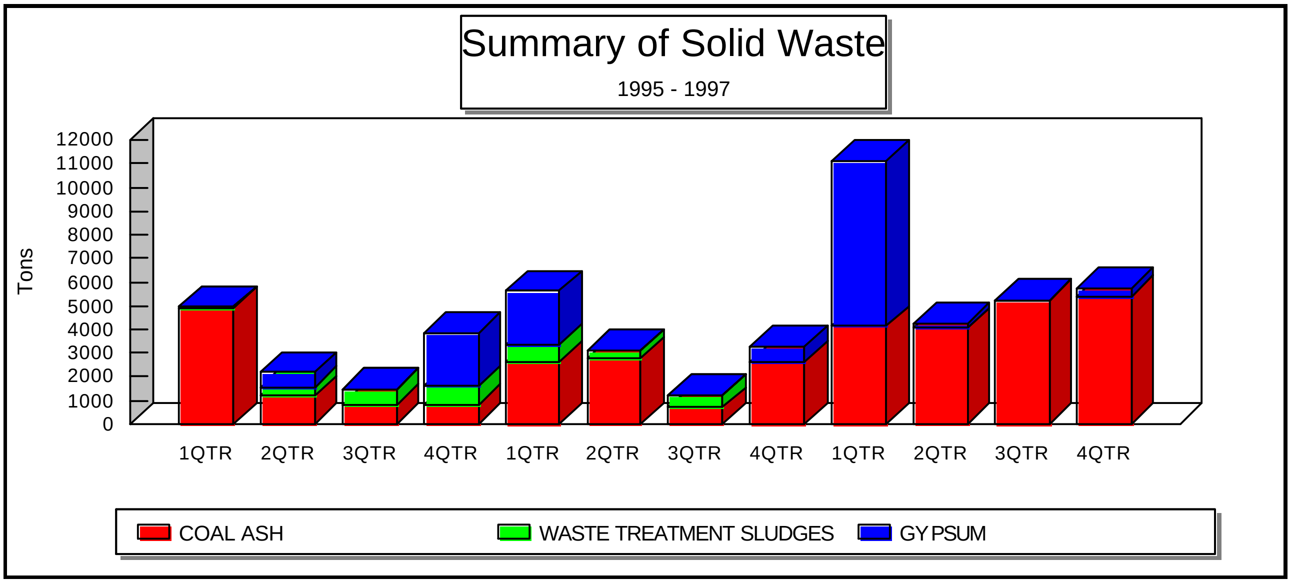
Milliken Station operates a solid waste disposal area east of the plant which encompasses approximately 41 acres. The disposal area began operation in 1978 and accepted primarily combustion byproducts from Milliken Station which included fly ash, bottom ash and pyrite rejects. In addition the facility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

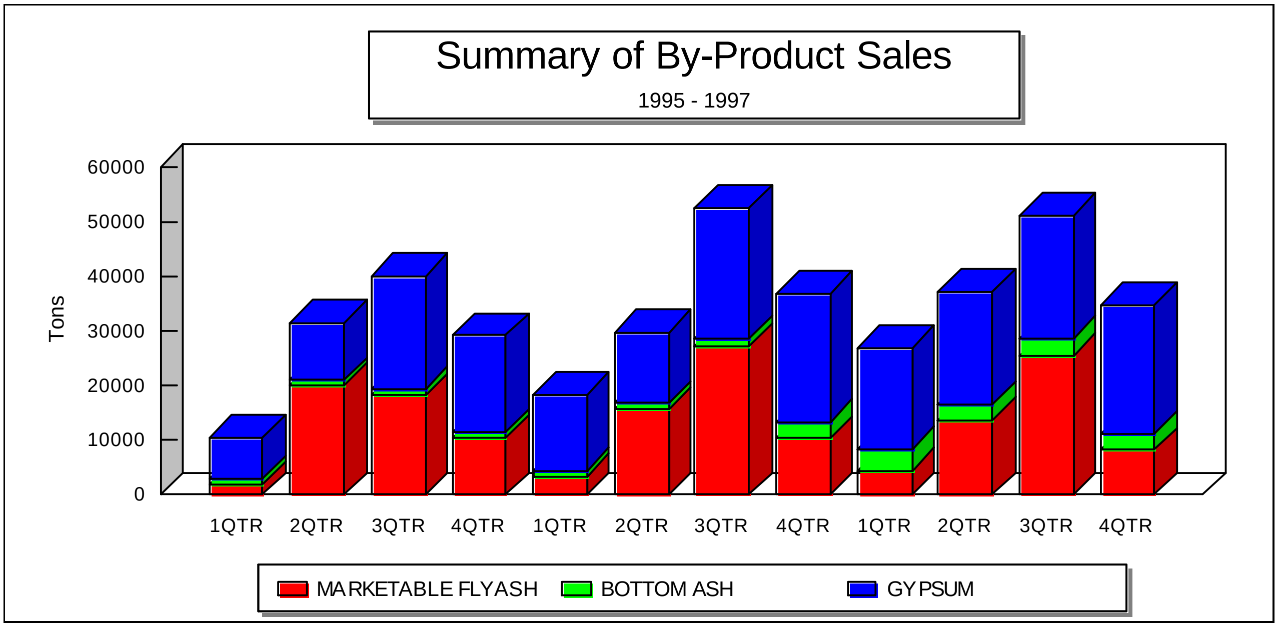
**FIGURE 8.12-1**



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 $SO_2$**,** $NO_X$ and particulate control systems. Removal efficiencies were determined for key air toxic compounds (Hg, Ni, As, Be, Cd, $Cr^{+6}$ , 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/$10^6$ 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 $SO_3$ 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/$10^{12}$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 µg/Nm$^3$ (excluding Method 2) and Hg(II) results ranged from 0.15-0.35 µg/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 µg/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 µg/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% $NO_X$ reduction can be seen between the two test programs with baseline stack emissions falling from 452 ppm @ 3% $O_2$ to 247 ppm @ 3% $O_2$.

- 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 $O_2$ during baseline testing of 3.8% verses 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 ($SO_2$) 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 $NO_X$ 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-$NO_X$ BURNERS ON UTILIZATION OF FLY ASH

Daily data on fly ash quality and $NO_X$ emissions gathered over a five-year (1992-1996) period from the Milliken Station demonstrated that a 39% reduction in $NO_X$ was achieved using LNCFS-3 low $NO_X$ 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-$NO_X$ 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 $NO_X$ emissions (30-day rolling average) for the two units were averaged individually and the monthly values used to monitor the $NO_X$ emissions from the station. The average of $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $NO_X$ 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 $CaCl_2$ industry in North America, with a view towards identifying potential market opportunities for selling $CaCl_2$, which can be produced by upgrading FGD waste streams. The report begins with a section on the sources of $CaCl_2$ and production methods worldwide. It then describes in detail the major worldwide uses for $CaCl_2$, Next, the report gives the various product forms and specifications. The final section contains details on $CaCl_2$ 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 $CaCl_2$ in the United States (as opposed to incurring the cost of disposal).
- At a minimum, utilities should plan to produce $CaCl_2$ brines which are at least 32% $CaCl_2$ 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.
- $CaCl_2$ 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%,
- $CaCl_2$ is an undifferentiated commodity chemical with well-established, mature markets. The principal uses/markets for $CaCl_2$ 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.
- $CaCl_2$ is also produced in Europe and Asia for similar uses/markets as those in the United States and North America.
- Much of the $CaCl_2$ sold is in the form of 32%-38% brine, which is prohibitively expensive to transport over extended distances. Thus, while excess $CaCl_2$ production capacity does exist, utilities can capitalize on niche market opportunities if they produce by-product $CaCl_2$ 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 $CaCl_2$, as well as the network of distributors (which is the way that most $CaCl_2$ is sold).

If a utility is considering installing an FGD process and associated equipment to generate by-product $CaCl_2$ 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;<br>(1) 8' Diameter Bypass | Steel Shell (2) FRP Flues (1) Carbon Steel Bypass | Inter-national 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<br>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<br>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<br>80/90/100/110 TDH<br>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<br>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 |
| 1.2B.02 463 | Process Water Pump, PP-103, 203, 303 | 2 | 1 | 700 GPM<br>273' TDH, 75 HP | Horizontal Centrifugal Flow | Carbon Steel | Goulds |

| Item<br>No. | Item Name | Number<br>In Use | <br>Spare | Unit<br>Capacity | Design<br>Conditions | Material of<br>Construction | Vendor |
|---|---|---|---|---|---|---|---|
| 1.2B.02<br>464 | Absorber Slurry Drain Tank, TK-305 | 1 | 0 | 300,000 GALS | Vertical Cylindrical | Mastic Lined Concrete | San-Con |
| 1.2B.02<br>464 | Absorber Slurry Drain Tank Agitator, AG-305 | 1 | 0 | 20 HP | Top Mounted | Rubber Lined Carbon Steel | Lightnin |
| 1.2B.02<br>464 | Absorber Slurry Drain Pumps, PP-305A & PP-305B | 1 | 1 | 500 GPM<br>73' TDH, 20 HP | Horizontal Centrifugal Flow | Rubber Lined Carbon Steel | BGA |
| 1.2B.02<br>465 | Bleed Pumps, PP-112A&B, 212A&B | 2 | 2 | 500 GPM<br>133' TDH, 40 HP | Horizontal Centrifugal Flow | Rubber Lined Carbon Steel | BGA |
| 1.2B.02<br>466 | Formic Acid Tank, AST-301 | 1 | 0 | 5,000 Gal. | Vertical Cylindrical | 316L SS | Sterling Boiler |
| 1.2B.02<br>466 | Formic Acid Metering Pumps, AMP-101,201,301 | 2 | 1 | 6.2 GPM<br>60 PSI, .5 HP | Metering Pumps Diaphragm Type | 316L SS | Milton Roy |
| 1.2B.02<br>467 | Mist Eliminator Wash Spray Nozzles, WWN-025 | 56 | 0 | 10 GPM | Full Cone | Polypropylene | Bete |
| 1.2B.02<br>467 | Quench Water Spray Nozzles, EQN-0375,QNS-025 | 80 | 0 | 2 GPM | Pig Tail | Hastelloy | Lechler |
| 1.2B.02<br>467 | Recirc Spray Cocurrent Section Spray Nozzles | 106 | 0 | 875 GPM | Pig Tail | Silica Carbon | Lechler |
| 1.2B.02<br>467 | Recirc Spray Counter Current Spray Nozzles | 159 | 0 | 438 GPM | Pig Tail | Silica Carbon | Lechler |
| 1.2B.02<br>471 | Mist Eliminators, VME-101,102,201 & 202 | 4 | 0 | 416,000 ACFM | Chevron Vertical Flow 1st & 2nd Stage Mist Eliminators | FRP Polypropylene | Munters |

| Item No. | Item Name | Number | | Unit Capacity | Design Conditions | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
| | | In Use | Spare | | | | |
| 1.2B.03<br>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<br>260 | Vibrating Bin Discharger | 1 | 1 | 100 Ton/Hour<br>3 HP | 12' Diameter Inlet<br>2' Diameter Outlet<br>$60^0$ Conical Slope | Steel<br>Neoprene | Kinergy |
| 1.2B.03<br>260 | Dust Collection System<br>1DC-2, 1BVF-1, 1BVF-2, 1DC-1 | 4 | 0 | 161 Sq. Ft.<br>484 Sq. Ft.<br>150 Sq. Ft. | Insertable Venting Filters | Steel<br>Polyester | DCE |
| 1.2B.05<br>441 | Equalization Tank, TK-320 | 1 | 0 | 16,000 GALS | Vertical Cylindrical | Rubber Lined Carbon Steel | FMC |
| 1.2B.05<br>441 | Desaturation Tank, TK-321 | 1 | 0 | 3,225 GALS | Vertical Cylindrical | Rubber Lined Carbon Steel | IDI |
| 1.2B.05<br>441 | Heavy Metal Tank, TK-322 | 1 | 0 | 800 GALS | Vertical Cylindrical | Rubber Lined Carbon Steel | IDI |
| 1.2B.05<br>441 | Coagulation Tank, TK-323 | 1 | 0 | 420 GALS | Vertical Cylindrical | Rubber Lined Carbon Steel | IDI |
| 1.2B.05<br>441 | Ferric Chloride Tank, TK-325 | 1 | 0 | 185 GALS | Vertical Cylindrical | Rubber Lined Carbon Steel | IDI |
| 1.2B.05<br>441 | Organo Sulfide Tank, TK-326 | 1 | 0 | 132 GALS | Vertical Cylindrical | Rubber Lined Carbon Steel | IDI |
| 1.2B.05<br>441 | Lime Slurry Tank , TK-327 | 1 | 0 | 575 GALS | Vertical Cylindrical | Rubber Lined Carbon Steel | IDI |
| 1.2B.05<br>441 | Sludge Holding Tank , TK-328 | 1 | 0 | 24,000 GALS | Vertical Cylindrical | Rubber Lined Carbon Steel | IDI |
| 1.2B.05<br>441 | CPR Sludge Holding Tank , TK-329 | 1 | 0 | 24,000 GALS | Vertical Cylindrical | Carbon Steel | IDI |

| Item No. | Item Name | Number | | Unit Capacity | Design Conditions | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
| | | In Use | Spare | | | | |
| 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 |
| 1.2B.05 | 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<br>30' TDH, 2 HP | Horizontal Centrifugal Flow | Rubberized Cast Iron | IDI |

| Item No. | Item Name | Number | | Unit Capacity | Design Conditions | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
| | | In Use | Spare | | | | |
| 1.2B.05 441 | Sludge Waste Pumps, PP-323A, B | 1 | 1 | 50 GPM<br>70' TDH, 5 HP | Positive Displacement | Rubber Lined Carbon Steel | IDI |
| 1.2B.05 441 | Sludge Recycle Pumps, PP324A, B | 1 | 1 | 20 GPM<br>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<br>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<br>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<br>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<br>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, THI-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<br>4,000 Gal. | Falling Film Evaporator | Titanium | RCC |
| 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 |

| Item No. | Item Name | Number In Use | Number Spare | Unit Capacity | Design Conditions | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
| 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<br>450 HP | Centrifugal | Titanium/316 SS | Ingersoll-Rand |
| 1.2B.05 443 | FGD Blowdown Transfer Pumps, PP-311A, B | 1 | 1 | 30 GPM<br>3 HP | Horizontal Centrifugal Flow | Monel | Goulds |
| 1.2B.05 443 | Brine Concentrator Primary Feed Pumps, PP-312A, B | 1 | 1 | 40 GPM<br>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 | Chomium Proof Corp. |
| 1.2B.05 443 | Distillate Tank, TK-315 | 1 | 0 | 200 GPM | Vertical Cylindrical | 316 SS | Chomithon |
| 1.2B.05 443 | Primary Heat Exchanger, HE-311 | 1 | 0 | 30 GPM Feed<br>$88^0$ AT Feed<br>$106^0$ AT Distillate | Plate Type | Titanium GR1 | APV Crepaco |
| 1.2B.05 443 | Secondary Heat Exchanger, HE-312 | 1 | 0 | 30 GPM Feed<br>$61^0$ AT Feed<br>$74^0$ AT Distillate | Plate Type | Titanium GR1 | APV Crepaco |

| Item No. | Item Name | Number |  | Unit Capacity | Design Conditions | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
|  |  | In Use | Spare |  |  |  |  |
| 1.2B.05 443 | Deaerator Tower, DA-311 | 1 | 0 | 30 GPM | Vertical Cylindrical | FRP Polypropylene | Chomium 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<br>120 V Solenoid | Metering Pump | Polypropylene | Promient |
| 1.2B.05 443 | Acid Pumps, PP-313A,B | 1 | 0 | .084 GPH<br>120 V Solenoid | Metering Pump | Teflon | Promient |
| 1.2B.05 443 | Seed Recycle Pump, PP-318 | 1 | 0 | 20 GPM<br>3 HP, 75 PSI | Horizontal Centrifugal Flow | Ferralium 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<br>30 HP, 28 PSI | Horizontal Centrifugal Flow | Ferallium 255 | Goulds |
| 1.2B.05 | B.C. Secondary Feed Pumps, PP-316A,B | 1 | 0 | 30 GPM<br>7.5 HP, 54 PSI | Horizontal Centrifugal Flow | Monel | Goulds |
| 1.2B.05 | Distillate Pumps, PP-315A,B | 1 | 0 | 30 GPM<br>15 HP, 85 PSI | Horizontal Centrifugal Flow | 316 SS | Goulds |
| 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<br>2,000 HP | Single Speed W/Backward Curve Blades; Induced Air Cooled Bearings | Carbon Steel | Buffalo Forge |

| Item No. | Item Name | Number |  | Unit Capacity | Design Conditions | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
|  |  | In Use | Spare |  |  |  |  |
| 1.2B.15 475 | Absorber Inlet Isolation Dampers | 2 | 0 | 1,616,646 Lb/Hr<br>550,000 ACFM (Each) | Guillotine | Carbon Steel | Effox |
| 1.2B.15 475 | Absorber Crossover Isolation Dampers | 2 | 0 | 1,616,646 Lb/Hr<br>550,000 ACFM (Each) | Double Louver | Carbon Steel | Effox |
| 1.2B.15 475 | ID Fan Outlet Isolation Dampers | 4 | 0 | 808,300 Lb/Hr<br>253,000 ACFM (Each) | Double Louver | Carbon Steel | Effox |
| 1.2B.15 475 | Bypass Control Damper | 1 | 0 | 1,550,000 Lb/Hr<br>483,500 ACFM | Modulating Double Louver | Carbon Steel | Effox |

| Item<br>No. | Item Name | Number<br>In Use | <br>Spare | Unit<br>Capacity | Design<br>Conditions | Material of<br>Construction | Vendor |
|---|---|---|---|---|---|---|---|

## BALANCE OF PLANT

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1.2A&B.09&10<br>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<br>HP-001 | Heat Pipe | 2 | 0 | 250° F Gas Outlet | | Carbon Steel with Alloy Tubes | ABB Air Pre-heater |
| 1.2B.11<br>UI-200 | SNCR | 1 | 0 | | | Leased Equipment | NALCO |
| 1.2A&B.07&08<br>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 | 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: $SO_2$ 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 | Total | | | |
| 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 | With 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 | $679,668 | 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 Cocurrent Section Spray Nozzles | $501 | Exempt | Included | $0 | $188 | W/Field Labor | $689 | 85 | $58,546 | 1994 |

# APPENDIX B
# MAJOR EQUIPMENT COSTS
# AREA NO.800: $SO_2$ 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 | 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 | | | | | | | No. of Units | Total Cost | Year |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | F.O.B. Equipment | Sales Tax | Freight | Field Material | Field Labor | Indirect Field | Total | | | |
| 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 | $80,000 | W/Field Labor | 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 | $55,988 | Exempt | Included | $0 | $6,000 | W/Field Labor | $61,988 | 1 | $61,988 | 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<br>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 | $90,267 | 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 |

# 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.05 441 | Ferric Chloride Feed Pumps | W/FGD Equipment | Exempt | Included | $0 | W/Skid | W/Field Labor | $0 | 2 | $0 | 1994 |
| 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% | |
| | | FGD System Titles | $x1,000,000 | $/kW |
| | 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 | SO2 Removal System | 8.4 | 28.0 |
| | 900 | NOx 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

| Fixed O & M Costs | Units | Quantity | $ / Unit | $(xM)/Yr |
|---|---|---|---|---|
| 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 |
| | | | | |
| Variable Operating Costs | | | | |
| 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 x10^3 | 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

| Power Plant Attributes | Units | Value |
|---|---|---|
| Plant Capacity (net) | Mwe | 300 |
| Power Produced (net) | 10^9kWh/yr | 1.708 |
| Capacity Factor | % | 65.0% |
| Plant Life | yr | 15 |
| Coal Feed | 10^6tons/yr | 0.629 |
| Sulfur in Coal | wt % | 3.2% |

| Emissions Control Data | Units | SO2 | NOx | TSP | PM10 |
|---|---|---|---|---|---|
| Removal Efficiency | % | 95.0% | | | |
| Emissions Standard | lb/10^6BTU | 1.20 | | | |
| Emissions Without Controls | lb/10^6BTU | 5.01 | | | |
| Emissions With Controls | lb/10^6BTU | 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% | |
| | FGD System Titles | $x1,000,000 | $/kW |
| 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 | SO2 Removal System | 9.2 | 30.7 |
| 900 | NOx 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

| Fixed O & M Costs | Units | Quantity | $ / Unit | $(xM)/Yr |
|---|---|---|---|---|
| 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 |
| | | | | |
| Variable Operating Costs | | | | |
| 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 x10^3 | 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

| Power Plant Attributes | Units | Value |
|---|---|---|
| Plant Capacity (net) | Mwe | 300 |
| Power Produced (net) | 10^9kWh/yr | 1.708 |
| Capacity Factor | % | 65.0% |
| Plant Life | yr | 15 |
| Coal Feed | 10^6tons/yr | 0.629 |
| Sulfur in Coal | wt % | 3.2% |

| Emissions Control Data | Units | SO2 | NOx | TSP | PM10 |
|---|---|---|---|---|---|
| Removal Efficiency | % | 95.0% | | | |
| Emissions Standard | lb/10^6BTU | 1.20 | | | |
| Emissions Without Controls | lb/10^6BTU | 5.01 | | | |
| Emissions With Controls | lb/10^6BTU | 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 | 7.53 | 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 - SO2 Basis | Factor | $/ton Removed | Factor | $/ton Removed |
| 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 - 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 |

## Magnesium Enhanced Lime

CAPITAL COSTS (market base)

| | | | |
|---|---|---|---|
| | Plant Size (Mw) | 300.0 | |
| | Capacity Factor | 65.0% | |
| | FGD System Titles | $x1,000,000 | $/kW |
| 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 | SO2 Removal System | 8.1 | 27.0 |
| 900 | NOx 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

| Fixed O & M Costs | Units | Quantity | $ / Unit | $(xM)/Yr |
|---|---|---|---|---|
| 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 |
| | | | | |
| Variable Operating Costs | | | | |
| 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 x10^3 | 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 |
| | | | | |
| Subtotal Variable Cost | | | | 5.81 |
| | | | | |
| Total O & M Cost (Fixed + Variable) | | | | 7.15 |

## Magnesium Enhanced Lime

| Power Plant Attributes | Units | Value |
|---|---|---|
| Plant Capacity (net) | Mwe | 300 |
| Power Produced (net) | 10^9kWh/yr | 1.708 |
| Capacity Factor | % | 65.0% |
| Plant Life | yr | 15 |
| Coal Feed | 10^6tons/yr | 0.629 |
| Sulfur in Coal | wt % | 3.2% |

| Emissions Control Data | Units | SO2 | NOx | TSP | PM10 |
|---|---|---|---|---|---|
| Removal Efficiency | % | 95.0% | | | |
| Emissions Standard | lb/10^6BTU | 1.20 | | | |
| Emissions Without Controls | lb/10^6BTU | 5.01 | | | |
| Emissions With Controls | lb/10^6BTU | 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% |  |
|  |  |  |  |  |
|  |  | FGD System Titles | $x1,000,000 | $/kW |
|  | 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 | SO2 Removal System | 8.4 | 27.9 |
|  | 900 | NOx 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

| Fixed O & M Costs | Units | Quantity | $ / Unit | $(xM)/Yr |
|---|---|---|---|---|
| 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 |
| | | | | |
| Variable Operating Costs | | | | |
| 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 x10^3 | 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

| Power Plant Attributes | Units | Value |
|---|---|---|
| Plant Capacity (net) | Mwe | 300 |
| Power Produced (net) | 10^9kWh/yr | 1.708 |
| Capacity Factor | % | 65.0% |
| Plant Life | yr | 15 |
| Coal Feed | 10^6tons/yr | 0.629 |
| Sulfur in Coal | wt % | 3.2% |

| Emissions Control Data | Units | SO2 | NOx | TSP | PM10 |
|---|---|---|---|---|---|
| Removal Efficiency | % | 95.0% | | | |
| Emissions Standard | lb/10^6BTU | 1.20 | | | |
| Emissions Without Controls | lb/10^6BTU | 5.01 | | | |
| Emissions With Controls | lb/10^6BTU | 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% |  |
|  | FGD System Titles | $x1,000,000 | $/kW |
| 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 | SO2 Removal System | 8.3 | 27.6 |
| 900 | NOx 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

| Fixed O & M Costs | Units | Quantity | $ / Unit | $(xM)/Yr |
|---|---|---|---|---|
| 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 |
| | | | | |
| Variable Operating Costs | | | | |
| 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 x10^3 | 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

| Power Plant Attributes | Units | Value |
|---|---|---|
| Plant Capacity (net) | Mwe | 300 |
| Power Produced (net) | 10^9kWh/yr | 1.708 |
| Capacity Factor | % | 65.0% |
| Plant Life | yr | 15 |
| Coal Feed | 10^6tons/yr | 0.629 |
| Sulfur in Coal | wt % | 3.2% |

| Emissions Control Data | Units | SO2 | NOx | TSP | PM10 |
|---|---|---|---|---|---|
| Removal Efficiency | % | 95.0% | | | |
| Emissions Standard | lb/10^6BTU | 1.20 | | | |
| Emissions Without Controls | lb/10^6BTU | 5.01 | | | |
| Emissions With Controls | lb/10^6BTU | 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% | |
| | | FGD System Titles | $x1,000,000 | $/kW |
| | 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 | SO2 Removal System | 7.6 | 25.2 |
| | 900 | NOx 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

| Fixed O & M Costs | Units | Quantity | $ / Unit | $(xM)/Yr |
|---|---|---|---|---|
| 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 |
| | | | | |
| Variable Operating Costs | | | | |
| 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 x10^3 | 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

| Power Plant Attributes | Units | Value |
|---|---|---|
| Plant Capacity (net) | Mwe | 300 |
| Power Produced (net) | 10^9kWh/yr | 1.708 |
| Capacity Factor | % | 65.0% |
| Plant Life | yr | 15 |
| Coal Feed | 10^6tons/yr | 0.629 |
| Sulfur in Coal | wt % | 3.2% |

| Emissions Control Data | Units | SO2 | NOx | TSP | PM10 |
|---|---|---|---|---|---|
| Removal Efficiency | % | 95.0% | | | |
| Emissions Standard | lb/10^6BTU | 1.20 | | | |
| Emissions Without Controls | lb/10^6BTU | 5.01 | | | |
| Emissions With Controls | lb/10^6BTU | 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 | 6.76 | 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)

| | | | | |
|---|---|---|---|---|
| | | CAPITAL COSTS (market base) | | |
| | | Plant Size (Mw) | 300.0 | |
| | | Capacity Factor | 65.0% | |
| | | | | |
| | | FGD System Titles | $x1,000,000 | $/kW |
| | 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 | SO2 Removal System | 5.9 | 19.7 |
| | 900 | NOx 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)

| Fixed O & M Costs | Units | Quantity | $ / Unit | $(xM)/Yr |
|---|---|---|---|---|
| Operating Labor | Mnhr/hr | 27,040 | 23.00 | 0.62 |
| Maintenance Labor | | | | 0.18 |
| Maintenance Material | | | | 0.26 |
| Administration / Support Labor | | | | 0.24 |
| Subtotal Fixed Costs | | | | 1.30 |
| | | | | |
| Variable Operating Costs | | | | |
| 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 x10^3 | 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 |
| | | | | |
| Subtotal Variable Cost | | | | 3.44 |
| | | | | |
| Total O & M Cost (Fixed + Variable) | | | | 4.74 |

## Chiyoda Thoroughbred (CT 121)

| Power Plant Attributes | Units | Value |
|---|---|---|
| Plant Capacity (net) | Mwe | 300 |
| Power Produced (net) | 10^9kWh/yr | 1.708 |
| Capacity Factor | % | 65.0% |
| Plant Life | yr | 15 |
| Coal Feed | 10^6tons/yr | 0.629 |
| Sulfur in Coal | wt % | 3.2% |

| Emissions Control Data | Units | SO2 | NOx | TSP | PM10 |
|---|---|---|---|---|---|
| Removal Efficiency | % | 95.0% | | | |
| Emissions Standard | lb/10^6BTU | 1.20 | | | |
| Emissions Without Controls | lb/10^6BTU | 5.01 | | | |
| Emissions With Controls | lb/10^6BTU | 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% | |
| | | FGD System Titles | $x1,000,000 | $/kW |
| | 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 | SO2 Removal System | 10.5 | 34.9 |
| | 900 | NOx 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

| Fixed O & M Costs | Units | Quantity | $ / Unit | $(xM)/Yr |
|---|---|---|---|---|
| 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 |
| | | | | |
| Variable Operating Costs | | | | |
| 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 x10^3 | 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

| Power Plant Attributes | Units | Value |
|---|---|---|
| Plant Capacity (net) | Mwe | 300 |
| Power Produced (net) | 10^9kWh/yr | 1.708 |
| Capacity Factor | % | 65.0% |
| Plant Life | yr | 15 |
| Coal Feed | 10^6tons/yr | 0.629 |
| Sulfur in Coal | wt % | 3.2% |

| Emissions Control Data | Units | SO2 | NOx | TSP | PM10 |
|---|---|---|---|---|---|
| Removal Efficiency | % | 95.0% | | | |
| Emissions Standard | lb/10^6BTU | 1.20 | | | |
| Emissions Without Controls | lb/10^6BTU | 5.01 | | | |
| Emissions With Controls | lb/10^6BTU | 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% | |
| | | FGD System Titles | $x1,000,000 | $/kW |
| | 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 | SO2 Removal System | 8.1 | 27.0 |
| | 900 | NOx 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)

| Fixed O & M Costs | Units | Quantity | $ / Unit | $(xM)/Yr |
|---|---|---|---|---|
| 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 |
| | | | | |
| Variable Operating Costs | | | | |
| Fuels | | | | |
| n/a | Ton | | | |
| | | | | |
| Sorbent | | | | |
| Limestone | Ton | 65,993 | 15.00 | 0.99 |
| | | | | |
| Chemicals/Catalyst | | | | |
| Formic Acid | Lb | 171,845 | 0.43 | 0.074 |
| | | | | |
| Utilities | | | | |
| Electric Power | kW x10^3 | 35 | 0.050 | 1.76 |
| | | | | |
| 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 | 110,008 | 10.00 | 1.10 |
| | | | | |
| Subtotal Variable Cost | | | | 3.93 |
| | | | | |
| Total O & M Cost (Fixed + Variable) | | | | 5.25 |

## Saarberg-Holter (SHU)

| Power Plant Attributes | Units | Value |
|---|---|---|
| Plant Capacity (net) | Mwe | 300 |
| Power Produced (net) | 10^9kWh/yr | 1.708 |
| Capacity Factor | % | 65.0% |
| Plant Life | yr | 15 |
| Coal Feed | 10^6tons/yr | 0.629 |
| Sulfur in Coal | wt % | 3.2% |

| Emissions Control Data | Units | SO2 | NOx | TSP | PM10 |
|---|---|---|---|---|---|
| Removal Efficiency | % | 95.0% | | | |
| Emissions Standard | lb/10^6BTU | 1.20 | | | |
| Emissions Without Controls | lb/10^6BTU | 5.01 | | | |
| Emissions With Controls | lb/10^6BTU | 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 | 6.72 | 0.124 | 5.19 |
| Fixed O & M Cost | 1.293 | 1.00 | 1.000 | 0.78 |
| Variable Operating Cost | 1.293 | 2.97 | 1.000 | 2.30 |
| Total Cost | | 10.70 | | 8.27 |

| Levelized Cost - SO2 Basis | Factor | $/ton Removed | Factor | $/ton Removed |
|---|---|---|---|---|
| Capital Charge | 0.1604 | 299.96 | 0.124 | 231.89 |
| Fixed O & M Cost | 1.293 | 44.86 | 1.000 | 34.69 |
| Variable Operating Cost | 1.293 | 132.62 | 1.000 | 102.57 |
| Total Cost | | 477.44 | | 369.15 |

| 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 |