DOE/FE-0451

NEW YORK STATE ELECTRIC & GAS CORPORATION

MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

PROJECT PERFORMANCE SUMMARY
CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

NOVEMBER 2002

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New York State Electric & Gas Corporation

Milliken Clean Coal Technology Demonstration Project

Project Performance Summary
Clean Coal Technology Demonstration Program

Environmental Control Devices

Milliken Clean Coal Technology Demonstration Project

The S-H-U formic acid enhanced, wet limestone scrubber demonstrated up to 98% SO_2 removal; tile lining of the scrubber absorber module provided superior corrosion and abrasion resistance; and innovative scrubber installation beneath the plant stack proved to be an effective space saving measure.

Overview

The New York State Electric & Gas Corporation (NYSEG) demonstrated a combination of technologies at its Milliken Station in Lansing, New York, designed to: (1) achieve high sulfur dioxide (SO_2) capture efficiency, (2) bring nitrogen oxide (NO_x) emissions into compliance with Clean Air Act Amendments of 1990 (CAAA), (3) maintain high station efficiency, and (4) eliminate waste water discharge.

This project is part of the U.S. Department of Energy's (DOE) Clean Coal Technology Demonstration Program (CCTDP) established to address energy and environmental concerns related to coal use. DOE sought cost-shared partnerships with industry through five nationally competed solicitations to accelerate commercialization of the most promising advance coal-based power generation and pollution control technologies. The CCTDP, valued at over five billion dollars, has significantly leveraged federal funding by forging effective partnerships founded on sound principles. For every federal dollar invested, CCTDP participants have invested two dollars. These participants include utilities, technology developers, state governments, and research organizations. The project presented here was one of nine selected in January 1991 from 33 proposals submitted in response to the program's fourth solicitation.

At the heart of the Milliken project was the formic acid enhanced Saarberg-Holter-Umwelttechnik, GmbH (S-H-U) wet limestone flue gas desulfurization (FGD) process. The S-H-U process provides a unique combination of low-pH operation, formic acid enhancement, single-loop cocurrent /countercurrent absorption, and forced oxidation. The process achieved design performance of 98 percent SO_2 removal and produced wallboard grade gypsum in lieu of waste. Other project features included locating the S-H-U system below the flue gas stack and using a Stebbins tile lining for the S-H-U absorber module. The location proved to be an effective space saving measure and the tile lining showed superior abrasion and corrosion resistance. NO_x emission control was provided by ABB Combustion Engineering Services (now Alstom Power) Low-NO_x Concentric Firing System (LNCFS™) III low-NO_x burners. The LNCFS™ burners brought Milliken Station into compliance with the CAAA by reducing emissions 39 percent. Other systems evaluated to maintain high efficiency and achieve zero waste water discharge included a heat pipe air preheater, an artificial intelligence-based Plant Emission Optimization Advisor (PEOA™) control system, a brine concentration system, and a modified electrostatic precipitator (ESP). These support systems either proved valuable in meeting goals or showed potential.

The costs for an S-H-U FGD retrofit are competitive with regenerative flue gas scrubbing processes. In addition to achieving up to 98 percent SO_2 removal, this innovative technology eliminates the acres of sludge ponds typically associated with scrubbers by producing a commercial grade gypsum by-product. Morever, S-H-U process availability proved to be 99.9 percent.

The Project

The project stemmed from NYSEG's desire to bring the 300-MWe Milliken station into compliance with year 2000 SO_2 and NO_x emission requirements under the CAAA and an opportunity to evaluate a promising high-sulfur capture efficiency scrubber. Although 1950s vintage, the two 150 MWe units at Milliken had a history of high efficiency operation. The U.S. utility industry was interested in evaluating the S-H-U process because it incorporated many advanced features. Although developed and successfully demonstrated in Europe, the S-H-U was yet untested in the United States with its unique coal compositions.

NYSEG took the lead in structuring a project, with industry participation, to: (1) demonstrate the S-H-U process, (2) install the latest low-NO_x burners for the tangentially fired boiler (LNCFS™), (3) prevent creation of new waste streams from pollutant controls, (4) incorporate technologies to minimize the impact of the pollutant controls on plant efficiency, and (5) demonstrate a space saving scrubber installation. The Milliken plant was chosen not only for its history of efficient performance, but because it was representative of many power plants in the United States facing the prospect of installing emission controls.

This effort entailed independent evaluation of S-H-U process and associated systems components including a Stebbins split, tile-lined absorber module installed beneath the plant stack, a mist eliminator, and wet stack. Parametric analyses evaluated the effects of key process variables on SO_2 removal, such as formic acid concentration, number and location of recycle pumps in operation, and liquid-to-gas (L/G) ratio. Operational assessments examined pressure drop, formate loss, oxidation air and sorbent utilization, power requirements, and gypsum and chloride brine quality. Specific objectives included achieving up to 98 percent SO_2 removal, essentially eliminating damaging scale formation, enabling high operating efficiency at high-chloride concentrations, and producing salable gypsum and calcium chloride by-products in lieu of wastes.

The degree of NO_x control achieved by the LNCFS™ low-NO_x burners was evaluated, along with their impact on boiler efficiency and carbon in the fly ash. Operational assessments were also made on the support systems designed to enhance plant efficiency and eliminate waste streams. The support systems assessed were ABB Air Preheater's heat pipe air preheater, a Corrosion and Protection Centre Industrial Services' (CAPCIS, now Integriti Solutions) corrosion monitoring system for the air preheater, DHR Technologies' artificial intelligence-based PEOA™ control system, a brine concentration system, and a modified ESP.

Project Sponsor
New York State Electric & Gas Corporation

Additional Team Members
New York State Energy Research and Development — cofounder
Empire State Electric Energy Research Corporation — cofunder
Consolidation Coal Company — technical consultant
Electric Power Research Institute — cofunder
Saarberg-Hölter-Umwelttechnik, GmbH — technology supplier
The Stebbins Engineering and Manufacturing Company — technology supplier
ABB Air Preheater, Inc. — technology supplier

Location
Lansing, Tompkins County, NY (New York State Electric & Gas Corporation's Milliken Station, Unit Nos. 1 and 2). This station is currently owned by AES Corporation and is designated AES Cayuga.

Technology
Flue gas cleanup using S-H-U formic acid enhanced, wet limestone scrubber technology; ABB Combustion Engineering's LNCFS™ III; Stebbins' tile-lined split-module absorber; ABB Air Preheater's heat pipe air preheater; and DHR Technologies' PEOA™ Control System.

Plant Capacity/Production
300 MWe

Coal
Pittsburgh, Freeport, and Kittanning Coals; 1.6, 3.2, and 4.0 percent sulfur, respectively

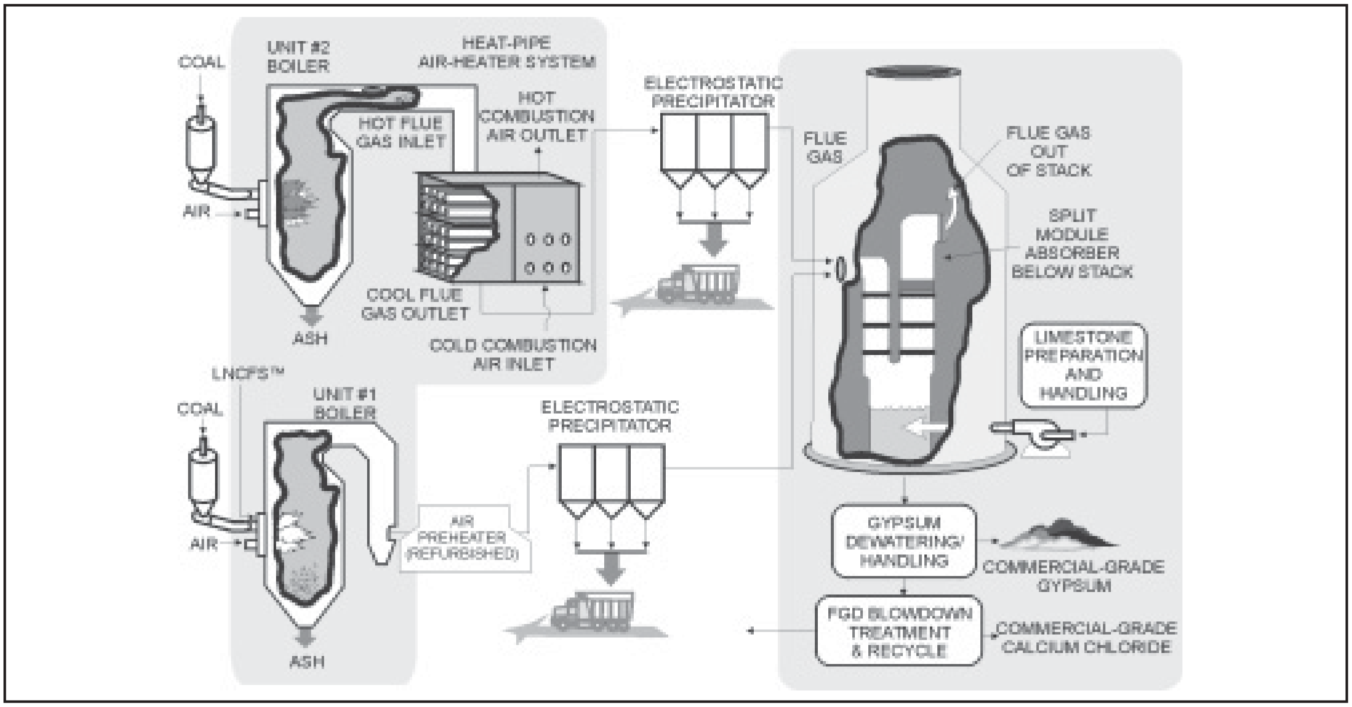
Demonstration Duration
January 1995 - November 1998

Project Funding

Total project cost	$158,607,807	100%
DOE	45,000,000	28%
Participant	113,607,870	72%

LNCFS is a trademark of ABB Combustion Engineering, Inc., and PEOA is a trademark of DHR Technologies, Inc.

The Technology



The LNCFS™ low-NO_x burners apply bulk furnace combustion staging to control NO_x emissions from the tangentially fired boiler and to keep carbon in fly ash levels at 4 percent or less (essential to fly ash sales). Concentric lean and rich combustion zones are created by diverting air away from the more centrally directed coal stream; and a portion of the secondary air is diverted to separated overfire air ports to complete combustion. A PEOA™ control system applies artificial intelligence techniques to optimize plant performance by measuring key boiler and balance of plant parameters and adjusting them to programmed set points.

Hot flue gas passes through a heat-pipe air preheater, which is designed to increase boiler efficiency by reducing both air leakage and the air preheater's flue gas exit temperature. A key feature is seal welding of the heat pipes to the division wall between the air and flue gas sections to preclude leakage at that juncture.

Flue gas from the from the air preheater is ducted to the top of the S-H-U absorber and flows cocurrently downward with recycle limestone slurry sprayed into the flue gas through an array of nozzles at four levels (three operating plus a spare) to absorb the SO_2. At the bottom of the cocurrent section, the recycle slurry disengages from the flue gas and collects in the absorber reaction tank. The partially scrubbed flue gas makes a 180 degree turn and flows upward through a countercurrent section. In the countercurrent section, the flue gas is sprayed with recycle limestone slurry from spray nozzles at three levels (two operating and one spare) to complete SO_2 absorption. The flue gas then passes through a two-stage mist eliminator before being discharged to a wet stack, which sits directly above the absorber. The absorber is a tile-lined, split-module design provided by Stebbins. For operating flexibility, the reinforced concrete vessel uses a center dividing wall to provide each Milliken unit with its own absorber module. Formic acid (HCOOH) acts as a buffer in the absorber and improves the rate of limestone dissolution and the solubility of calcium in the scrubbing liquid. Formic acid maintains a 4–5 pH ensuring formation of the easily oxidized, water soluble calcium bisulfite ($Ca(HSO_3)_2$), rather than the less soluble calcium sulfite ($CaSO_3$). This greatly increases the ease of oxidation to gypsum and essentially eliminates the potential for sulfite scaling within the absorber.

Blowers inject air into the reaction tank to oxidize the calcium bisulfite to calcium sulfate ($CaSO_4 \bullet H_2O$), *i.e.*, gypsum. Side-mounted agitators provide slurry mixing to prevent gypsum particles from settling to the bottom of the tank. The absorber slurry contains approximately 10 percent gypsum solids, which act as seed crystals for gypsum formation. A slurry slipstream is pumped from the absorber sump to a dewatering area, and is concentrated to approximately 45 percent solids in hydrocyclones and dewatered to greater than 90 percent solids in centrifuges.

Demonstration Results

Environmental

- The maximum SO_2 removal demonstrated was 98 percent with all seven recycle pumps operating and using formic acid. The maximum SO_2 removal without formic acid was 95 percent.
- The difference in SO_2 removal between the two limestone grind sizes tested (90%–325 mesh and 90%–170 mesh) while using low-sulfur coal was an average of 2.6 percentage points.
- The SO_2 removal efficiency was greater than the design efficiency during the high-velocity test of the cocurrent scrubber section up to an L/G of 110 gallons per 1,000 actual cubic feet of gas (gal/kacf).
- At full load, LNCFS™ III lowered NO_x emissions to 0.39 lb/10^6 Btu (compared to 0.64 lb/10^6 Btu for the original burners), a 39 percent reduction.
- LNCFS™ III maintained carbon in the fly ash below 4 percent and carbon monoxide emissions at baseline levels.

Operational

- For more than 30,000 hours, the S-H-U FGD unit demonstrated nearly 100 percent availability at capacity factors of 70–80 percent.
- The Stebbins tile-lined absorber demonstrated superior corrosion and abrasion resistance.
- The heat-pipe air preheater reduced power requirements by an average of 778 kW.
- Performance of a modified ESP with wider plate spacing and reduced plate area exceeded that of the original ESPs at lower power consumption.
- Boiler efficiency was essentially unchanged by the application of LNCFS™ III.

Economic

- The capital cost (1998$) of the FGD system is estimated at $300/kW for a 300-MWe unit with a 65 percent capacity factor, 3.2 percent sulfur coal, and 95 percent sulfur removal.
- The annual operating cost is estimated at $4.62 million (1998$); and the 15-year levelized cost is estimated at $412/ton of SO_2 removed (constant 1998$).

Figure 1. Effect of Countercurrent Headers on Pressure Drop

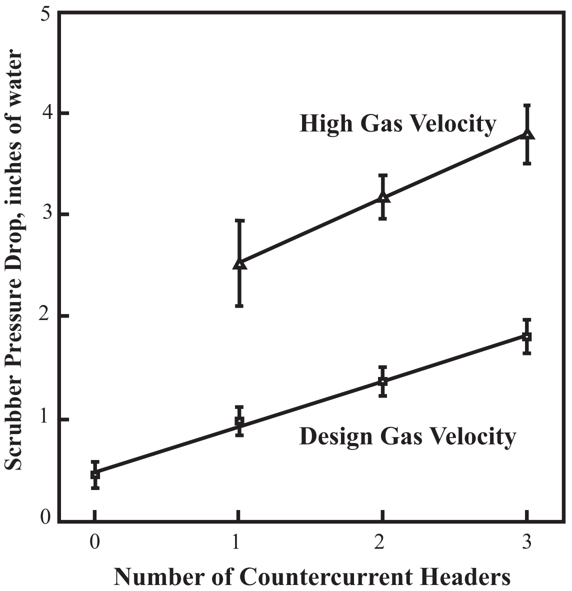


Table 1. Effect of Spray Header Out of Service on SO_2 Removal Rates‡

Header Not In Operation	SO_2 Removal Efficiency, %
A	86.7
B	93.4
C	90.7
D	91.5
E	87.3
F	90.2
G	91.7

‡ Cocurrent headers are A, B, C, and D and countercurrent headers are E, F, and G; with A and E being the top headers in their respective sections.

Environmental Performance

The Milliken Project, through its variety of innovative emissions control technologies, complied with all applicable federal and New York air, water, and solid waste environmental regulations and related permits. The test program was not as extensive as originally planned primarily because of time constraints imposed by the sale of the plant as part of the State of New York's electricity restructuring. However, parametric testing identified key variables effecting performance of demonstrated equipment, as well as performance potential; and successful follow-on commercial service provided by the equipment validated its compatibility with utility operating conditions.

FGD Performance. An overall assessment of the S-H-U process is that it performed well in tests burning low- (1.6 percent), design- (2.2 percent), and high- (3.2–4.1 percent) sulfur (S) coals. The S-H-U system was tested over a 36-month period. Typical evaluations included SO_2 removal efficiency, power consumption, process economics, load following capability, reagent utilization, by-product quality, and land additive effects. Parametric testing included formic acid concentration, L/G ratio, mass transfer, coal sulfur content, and flue gas velocity. The maximum SO_2 removal demonstrated was 98 percent with all seven recycle pumps operating and using formic acid, and the maximum SO_2 removal without formic acid was 95 percent. The unit operated routinely in the 90–95 percent SO_2 removal range.

Design-Sulfur Coal (2.2% S). Availability of design coal and time constraints truncated design coal testing. But, testing did show that the L/G ratio is an important variable for SO_2 removal. The SO_2 removal efficiency ranged from 85.6 percent with five spray headers in service to 95.1 percent with all seven spray headers in service, while using a nominal 800 parts per million (ppm) formic acid concentration, a limestone grind of 90 percent passing through 170 mesh, and a gas velocity rate of 20 feet per second (ft/s) in the cocurrent section. More SO_2 removal was achieved when a higher percentage of the total slurry was sprayed in the countercurrent section.

A single test indicated the importance of pH. The SO_2 removal rates ranged from 91.5 percent at a normal pH of 4.1 ± 0.1 to 85.4 percent at a lowered pH of 3.9, with all other operating conditions the same.

The cocurrent pumps had no measurable effect on pressure drop, whereas the countercurrent pumps significantly increased the scrubber pressure drop. As shown in Figure 1, the average effect of each countercurrent header was to increase pressure drop by 0.45 inches of water in the design flow tests (20 ft/s) and 0.64 inches of water in the high velocity tests (30–35 ft/s).

For the tests in which fewer than seven spray headers were operating, SO_2 removal depended on which spray headers were not in service. Results with six of the seven spray headers in operation are shown in Table 1. SO_2 removal efficiencies were lowest with the top header in each section out of service because they have the longest contact time with the flue gas.

Low-Sulfur Coal (1.6% S). A shortened demonstration period and availability problems with design coal resulted in most testing being performed on the low-sulfur coal. Parametric test were performed on the full range of variables.

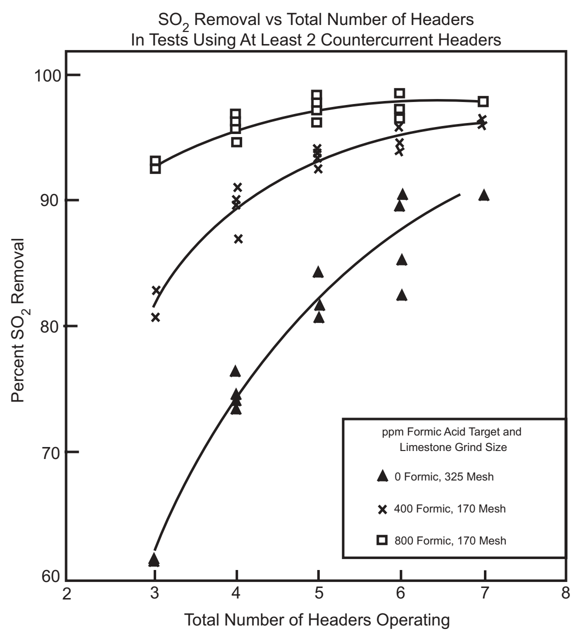
As shown in Figure 2, the number of spray headers in service impacted SO_2 removal efficiency. Also, the SO_2 removal rate ranged from a low of 30 percent using only two spray headers without formic acid to 98 percent using all seven spray headers and 800 ppm of formic acid. The maximum SO_2 removal was 98 percent at a 95 percent confidence level of ± 0.7 percent.

The SO_2 removal efficiency was increased significantly with the addition of formic acid. With five spray headers in service, SO_2 removal efficiency increased from 82 percent without formic acid to 97 percent with 800 ppm of formic acid added. Formic acid effects diminished with increasing concentration.

The pH of the spray slurry affected SO_2 removal efficiency. Increasing the pH from 4.2 to 5.0 without formic acid additive increased SO_2 removal efficiency an average of 10.1 percentage points.

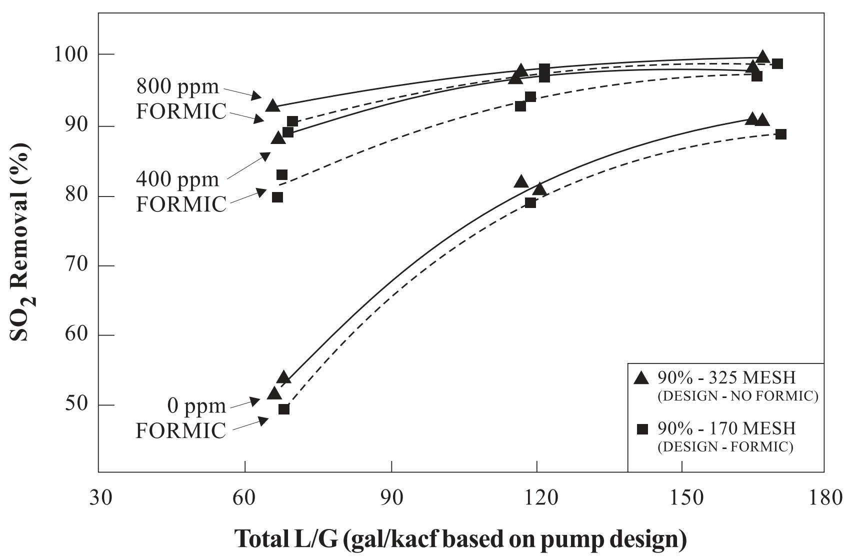
Nine tests were performed using an alternative limestone grind size. Higher SO_2 removal resulted using the finer grind (90 percent passing through 325 mesh) limestone in lieu of the coarser grind (90 percent passing through 170 mesh). The average difference in SO_2 removal between the two grind sizes was 2.6 percentage points, as shown in Figure 3.

Figure 2. Effect of Number of Spray Headers in Service and Formic Acid Concentration on FGD System Efficiency†



† At least two countercurrent headers in service.

Figure 3. Effect of Limestone Grind on SO_2 Removal



The S-H-U absorber is located beneath the stack, which saves space for plants that have space constraints.

Chloride concentration had little effect on SO_2 removal efficiency at concentrations below about 5 percent (50,000 ppm).

The SO_2 removal efficiency during high velocity tests (30–35 ft/s) ranged from 91 percent to 98 percent. The SO_2 removal efficiency was greater than the design efficiency during the high-velocity test of the cocurrent scrubber section up to a L/G ratio of 110 gal/kacf. For example, SO_2 removal averaged 95 percent at 94 gal/kacf in the design velocity (20 ft/s) tests and 98 percent at a comparable rate of 89 gal/kacf in the high velocity tests.

High-Sulfur Coal (3.2–4.1% S). During these tests, the sulfur level of the coal ranged from 3.2 percent to 4.1 percent, and averaged 3.64 percent. Both time constraints and slurry pump capacity limited high-sulfur coal testing. The slurry pump design capacity was below that required to control pH for coals at the upper end of the sulfur range. Nevertheless, certain conclusions were reached as a result of these tests.

As expected, the sulfur removal efficiency decreased as the coal sulfur content increased. The SO_2 removal efficiency depended more on the system pH than the L/G ratio. At a pH of 3.15, the SO_2 removal was 43.7 percent, and at a pH of 4.85 the SO_2 removal was 97.6 percent. Indications were that an S-H-U with higher slurry pump design capacity would perform at high SO_2 removal efficiencies using high sulfur coals.

Low-NO_x Burner Performance. At full boiler load (145–150 MWe) and 3.0–3.5 percent economizer oxygen (O_2), the LNCFS™ III system lowered NO_x emissions from a baseline value of 0.64 lb/10^6 Btu to 0.39 lb/10^6 Btu, a 39 percent reduction. At a reduced boiler load of 80–90 MWe and 4.3–5.0 percent economizer O_2, the LNCFS™ III system lowered NO_x emissions from a baseline value of 0.58 lb/10^6 Btu to 0.41 lb/10^6 Btu, a 29 percent reduction. Carbon in the fly ash was maintained below 4 percent and carbon monoxide emissions did not increase.

ESP Performance. Performance of the modified ESP with wider plate spacing (16 inches), less than half the plate area, and reduced power consumption, exceeded that of the original ESP. The average particulate matter penetration before the ESP modification was 0.22 percent and decreased to 0.12 percent after the modification.

Air Toxics. Comprehensive air toxic emissions and characterization testing was carried out during the Milliken demonstration. In summary, the ESP and FGD combined to remove 99.81 percent of trace elements found primarily in the solid phase, with the ESP averaging 99.7 percent removal. The ESP removed 99.96 percent of the major ash elements. The ESP removal efficiency for mercury was 16.7 percent and the FGD removal efficiency was 59.8 percent. With the exception of selenium, ESP inlet trace and major element results were in good agreement. Hexavalent chromium results show 26 percent combined removal by the ESP/FGD, but the stack readings were 4.2 times higher than the coal sample. The FGD removed the gas phase chlorides, fluorides, and sulfur at average efficiencies of 99.4 percent, 98.7 percent, and 93.1 percent, respectively. Toxic hydrocarbon measurements typically hovered around the non-detectable threshold. Particle size distribution at the ESP outlet averaged 76 percent less than 10 microns, 56 percent less than 2.5 microns, and 36 percent less than 1 micron.

Operational Performance

The demonstrated technologies are still in service at the Milliken Plant, with the exception of the brine concentrating system. The gypsum and fly ash byproducts continue to be marketed.

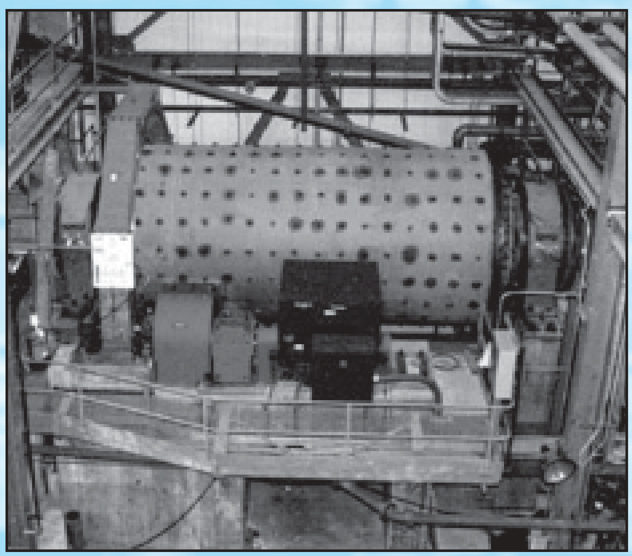
FGD Performance. For more than 30,000 hours of demonstration operation, the S-H-U FGD unit reliability was high and availability held at nearly 100 percent at capacity factors of 70–80 percent. Unit thermal efficiencies hovered around 35 percent. However, some initial problems had to be overcome and the demonstration identified some areas to improve performance in future applications.

Plugging of slurry spray nozzles and hydroclone elements occurred. This problem was traced to rubber coming off the rubber-clad turning vanes in the absorbers. Also, gypsum deposits were forming on equipment surfaces, contributing to spray nozzle plugging. This occurrence resulted from insufficient gypsum seed crystals in the absorber tank slurry. Cleaning of the brittle ceramic spray nozzles proved difficult without some breakage and some were replaced with stellite units. These difficulties were resolved by installing screens at the slurry pump intakes and keeping gypsum levels up in the absorber reaction tank. No further spray nozzle cleaning was needed, suggesting that ceramic nozzles offer satisfactory service.

Mixing of constituents in the absorber reaction tank proved to be less than optimum and resulted in gypsum settling out and blocking slurry pump intakes, primarily those adjacent to the divider wall. The cause was installation of mixers only along the outside walls of the split-module absorber. The solution was to operate the slurry pumps continuously, which compromised the objective of minimizing power requirements.

The expected high limestone utilization, due to formic acid enabled low pH, was somewhat compromised by the relatively close proximity of the limestone injection and gypsum bleed pump suction ports, causing some limestone to be drawn off with the gypsum. Poor mixing in the absorber tank exacerbated the situation. The problem was largely resolved by moving the limestone injection port further into the tank. But, wider separation is warranted in future designs.

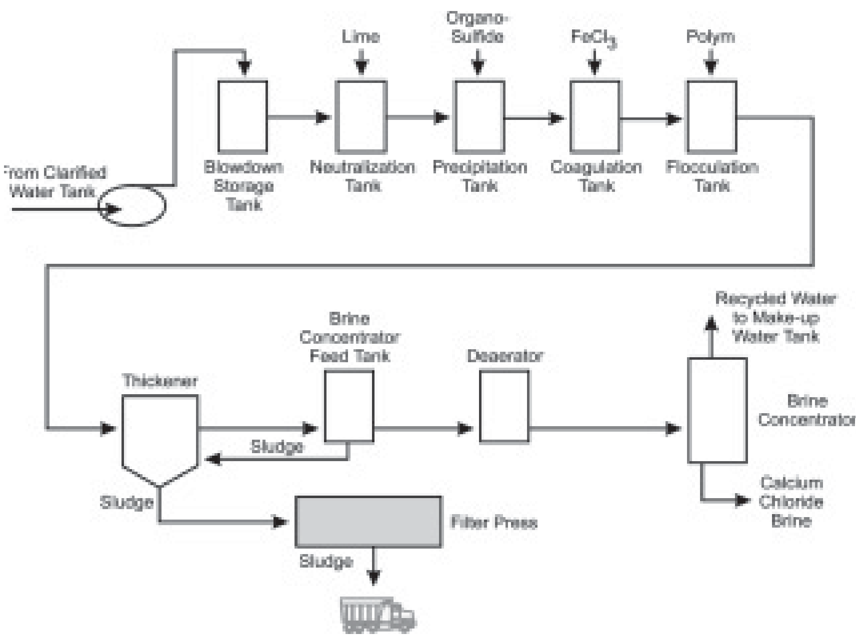
The Stebbins split-module tile-lined absorber demonstrated superior abrasion and corrosion resistance, suggesting a liner life three to four times that of rubber liners. The corrosion resistance was an essential element in enabling operation in the chemically harsh conditions associated



Limestone ball mill at Milliken Station

with high chloride and low pH absorption slurries. The construction allowed installation beneath the stack to save space and the configuration allowed flexibility in operation and maintenance (one unit can be shut down for low load situations or for on-line repairs).

Figure 4. Blow Down Treatment and Brine Concentration Flow Diagram



Brine Concentration System. As shown in Figure 4, a brine concentration system removes chlorides from the FGD blow down pretreatment system effluent. It is designed to control chloride levels, produce a commercially salable calcium chloride brine, and enable recycle of process water. Technical problems prevented satisfactory operation of the brine concentration system. These included excessive vibration in the brine concentrator vapor compressor, a high boron concentration in the feed line to the brine concentrator, suspended solids in the concentrated brine, scaling and plugging of the evaporator tubes, and corrosion in various parts of the system. Although progress was made in solving these problems, a salable concentrated brine solution was not produced as part of the Milliken Project. Without the brine concentrator system, the project goal of zero wastes was not achieved. However, project sponsors believed that with some additional effort, this system could be made to operate satisfactorily, thereby eliminating another waste-disposal problem.

Low-NO_x Burner Performance. Boiler efficiency was 88.3–88.5 percent using LNCFS™ III, compared to a baseline of 89.3–89.6 percent. The lower boiler efficiency was attributed to higher post-retrofit flue gas O_2 levels and higher stack temperatures, which accompanied the air preheater retrofit. The LNCFS™ III and baseline results were adjusted so that they could be compared at similar flue gas temperatures. Under comparable conditions, the LNCFS™ III boiler efficiency was estimated to be 0.2 of a percentage point higher than baseline.

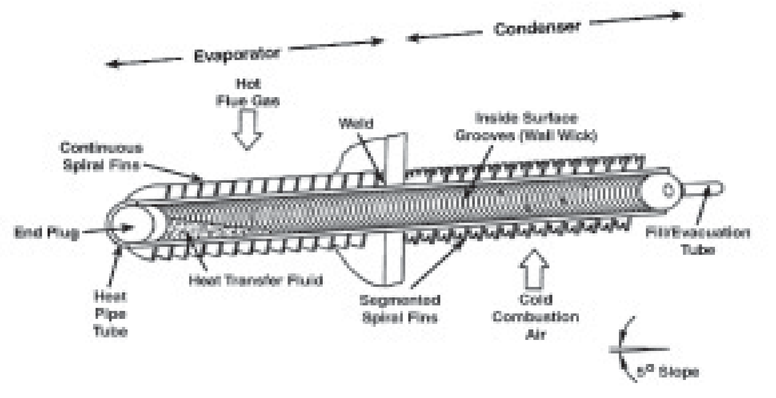
Heat Pipe Air Preheater. The heat pipe depicted in Figure 5 operates on the principle of a hot gas evaporating a fluid in a canted tube, drawing the heat of evaporation from the hot gas, and cold gas condensing the vapor, giving up the heat of evaporation. The canted configuration causes the fluid to recycle and lends itself to sealing at the evaporation/condensation interface. An expected thermal efficiency boost from applying the heat pipe principle did not materialize (a 20° F reduction in flue gas exit temperature was projected), but an overall efficiency gain resulted from reduced leakage. Fan power savings averaged 778 kW, or about 0.49 percent of gross load. Pressure losses across flue gas and air sides were less than the design values of 3.65 inches of water and 5.35 inches of water, respectively. Some air leakage was experienced at the soot blower penetrations at full load.

ESP. Performance tests on the original and modified ESPs showed that the modified ESP had better removal efficiency, as discussed previously, even though it had one-half of the collection plate area of the original ESP. The data show that the power requirement is 25 percent less than that of the original ESP.

POEA™. The POEA™ control system is an online support system designed to help meet economic performance targets by integrating key information and analyses that assist plant personnel in optimizing plant performance, including steam and waste management systems. Although not necessary for S-H-U operation, the promise of POEA™ is that it will compensate for parasitic power losses. Due to data collection problems, the two tests on the POEA™ system were promising, but inconclusive.

CAPCIS. NYSEG installed and tested an online, real-time corrosion monitoring system to identify the lowest flue gas outlet temperature possible without compromising equipment subject to corrosion. Probes were placed at the heat pipe air preheater outlet and S-H-U FGD inlet duct. Software was to use probe signals to control the secondary air bypass damper in the heat pipe preheater. At the time of the final report, the control software had been redesigned from a DOS-based system to a UNIX-based system, which required significant software and hardware changes at the plant. As such, data was insufficient to draw any conclusions on the system.

FIGURE 5. HEAT PIPE CROSS SECTION



The gypsum cake is loaded onto trucks for delivery to the purchaser.

Economic Performance

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. The underlying costs for a mature commercial equivalent of the FGD elements of the Milliken demonstration project are the installed costs for equipment for the Milliken Project. Since the equipment utilized at the Milliken Station in many cases serviced one (or both) of the two existing 150 MWe units, it was necessary to adjust the quantities of many of the project's components in order to normalize the commercial plant scope to allow for the differences in both capacity and performance. The basis for the cost figures used are retrofit costs, thus eliminating the need for any "retrofit cost" adjustments.

The estimated capital cost of the total FGD system in 1998 dollars was estimated at $300/kW for a 300-MWe unit with a 65 percent capacity factor using 3.2 percent sulfur coal and achieving 95 percent sulfur removal. The annual operating cost is estimated at $4.62 million. The 15-year levelized cost is estimated at $412/ton of SO_2 removed in 1998 constant dollars.

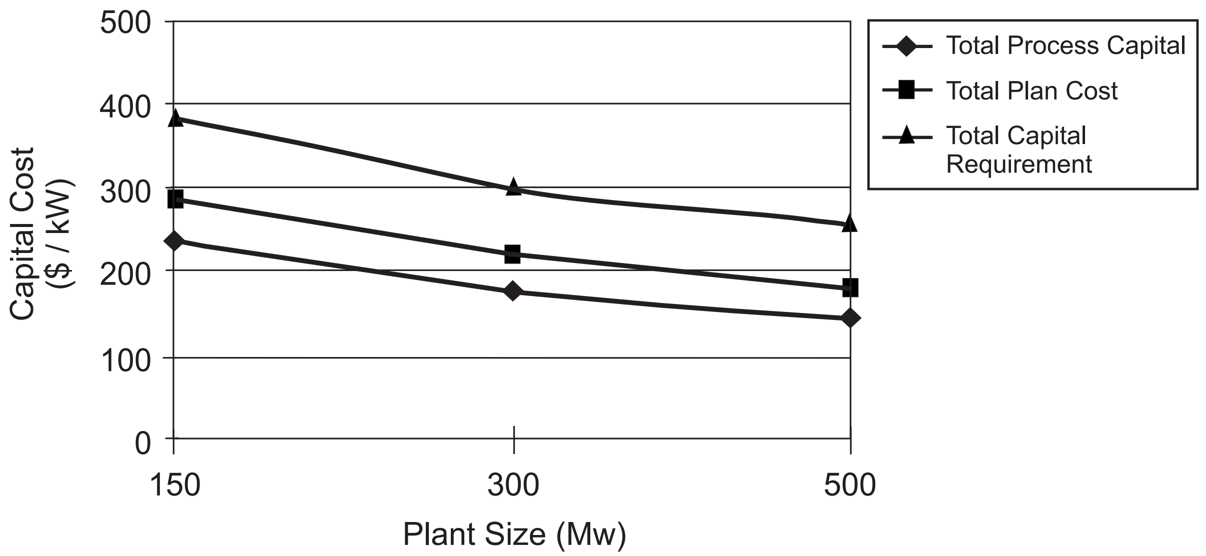
When plotted on a unit cost basis, costs decrease markedly, demonstrating a clear and significant economy of scale as shown in Figure 6. On a unit cost basis, total capital requirements for an S-H-U FGD retrofit similar to Milliken Station can be expected to range from $385/kW for a 150 MW plant to $260/kW for a 500 MW plant.

Commercial Applications

The S-H-U process, Stebbins absorber module, and heat-pipe air preheater are applicable to virtually all coal-fired power plants. In a NYSEG analysis, the total U.S. electric market for which the S-H-U process was applicable was divided into two parts: retrofit capacity (pre-NSPS coal-fired boilers not equipped with SO_2 controls) and new capacity (projected coal-fired additions through 2030). This analysis suggests a total potential retrofit market of 5,700 MWe through 2030 and a potential new power plant market of 96,200 MWe. Although done in 1995, this analysis remains reasonably accurate. The successful demonstration of the S-H-U process at Milliken, along with extensive use in Europe, should enable S-H-U to effectively market its FGD technology in the United States through its U.S. design and manufacturing partners.

The LNCFS™ system has the potential commercial application to over 400 U.S. pulverized coal, tangentially fired utility units. These units range from 25 MWe to 950 MWe in size and burn a wide range of coals, from low-volatile bituminous to lignite. As of September 2001, about 63 GW of LNCFS™ burners have been sold. Of this amount, about 49 GW are equipped with overfire air and 14 GW are without overfire air. Total sales are estimated at $1.3 billion.

Figure 6. Capital Costs for Retrofit S-H-U FGD System



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