Milliken Clean Coal Technology Demonstration Project

Project completed

Participant

New York State Electric & Gas Corporation (NYSEG)

Additional Team Members

New York State Energy Research and Development Authority—cofunder

Empire State Electric Energy Research Corporation—cofunder

Consolidation Coal Company—technical consultant

Saarberg-Hölter Umwelttechnik, GmbH (S-H-U)—technology supplier

The Stebbins Engineering and Manufacturing Company—technology supplier

ABB Air Preheater, Inc.—technology supplier

Electric Power Research Institute—cofunder

Location

Lansing, Tompkins County, NY (NYSEG's Milliken Station, Unit Nos. 1 and 2). This station is currently owned by AES Corporation and is designated AES Cayuga.

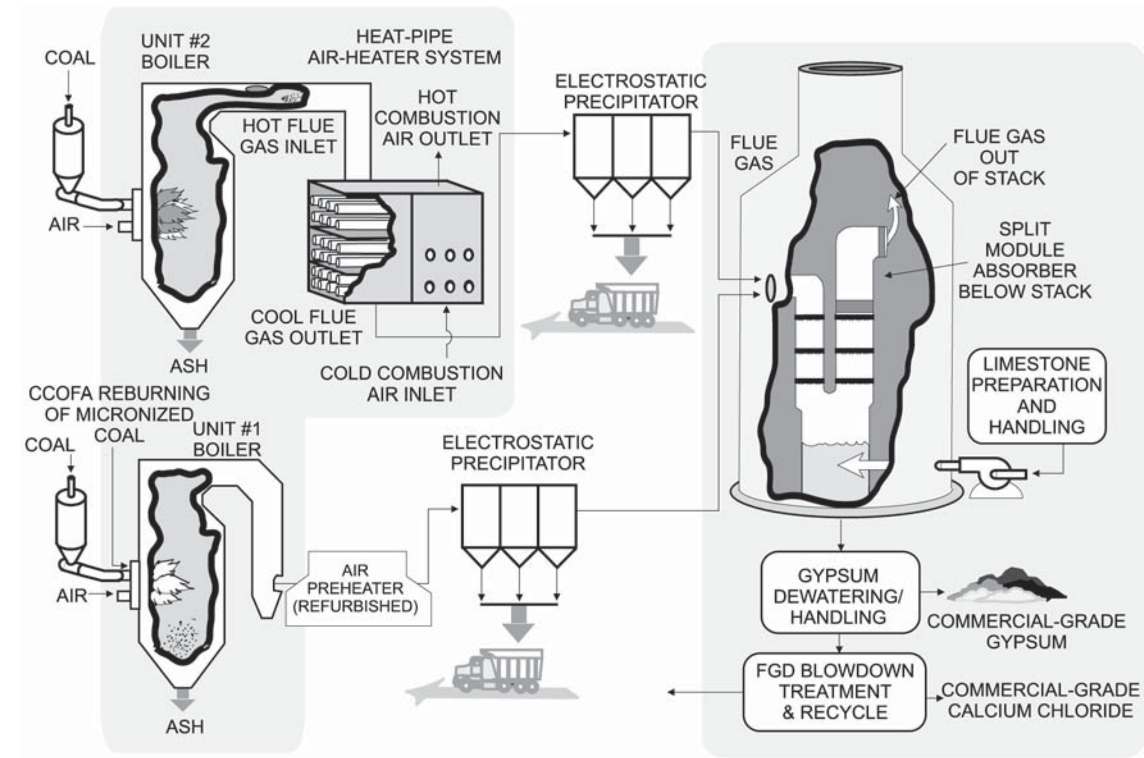
Technology

Flue gas cleanup using S-H-U formic-acid-enhanced, wet limestone scrubber technology; ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™) Level III; Stebbins' tile-lined, split-module absorber; ABB Air Preheater's heat-pipe air preheater; and NYSEG's PEOA Control System.

Plant Capacity/Production

300 MWe

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



Coal

Pittsburgh, Freeport, and Kittanning Coals; 1.5, 2.9 and 4.0% sulfur, respectively.

Project Funding

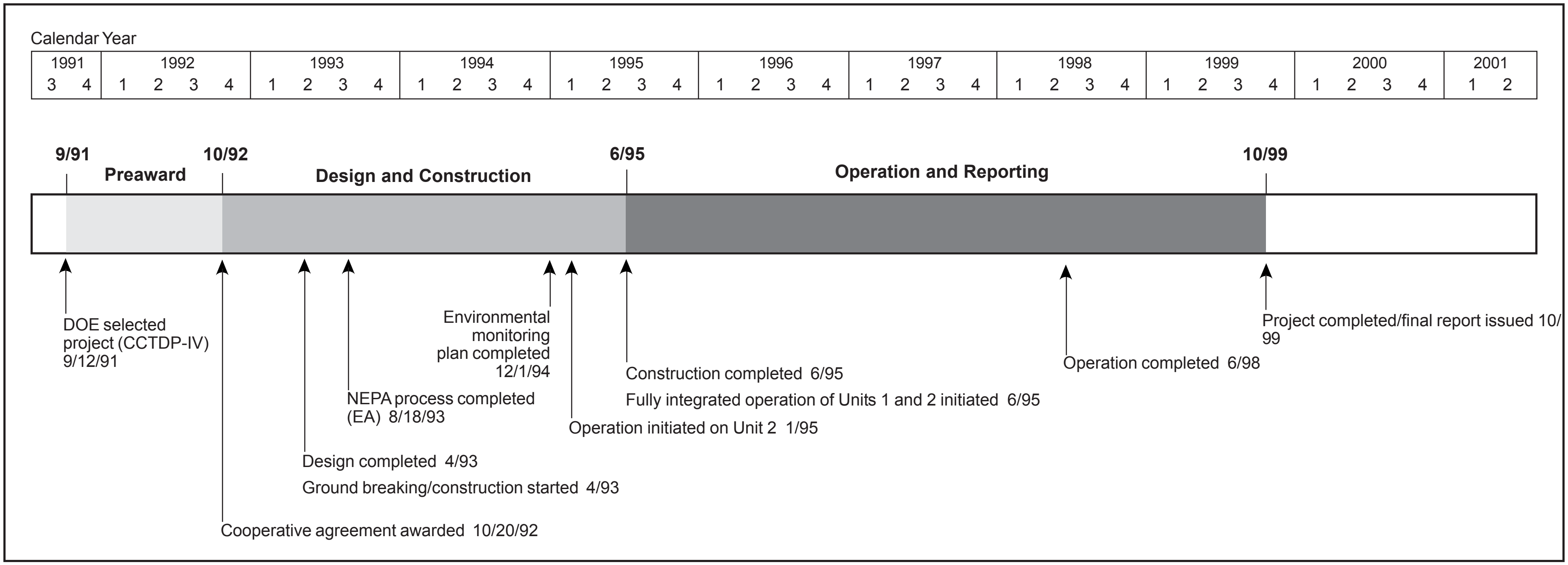
Total	$158,607,807	100%
DOE	45,000,000	28
Participant	113,607,807	72

Project Objective

To demonstrate high sulfur capture efficiency and NO_x and particulate control at minimum power requirements, zero waste water discharge, and the production of by-products in lieu of wastes.

Technology/Project Description

The formic acid enhanced S-H-U process is designed to remove up to 98% of SO_2 at high sorbent utilization rates. The Stebbins tile-lined, split-module reinforced concrete absorber vessel provides superior corrosion and abrasion resistance. Placement below the stack saves space and provides operational flexibility. NO_x emissions are controlled by LNCFS III™ low-NO_x burners. A heat-pipe air preheater is integrated to increase boiler efficiency by reducing both air leakage and the air preheater's flue gas exit temperature. To enhance boiler efficiency and emissions reductions, a Plant Emission Optimization Advisor (PEOA) provides state-of-the-art, artificial-intelligence-based control of key boiler and plant operating parameters. (See Micronized Coal Reburning Demonstration for NO_x Control for another CCT Program project at this unit.)



Results Summary

Environmental

- The maximum SO_2 removal demonstrated was 98% with all seven recycle pumps operating and using formic acid. The maximum SO_2 removal without formic acid was 95%.
- 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 concurrent scrubber section up to a liquid-to-gas ratio (L/G) of 110 gallons per 1,000 actual cubic feet (kacf) of gas.
- 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% reduction.
- LNCFS™ III maintained carbon in the fly ash below 4% and carbon monoxide emissions at baseline levels.

Operational

- For more than 30,000 hours, the S-H-U FGD unit demonstrated nearly 100% availability at capacity factors of 70–80%.
- 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.
- Boiler efficiency was 88.3–88.5% for LNCFS™ III, compared to a baseline of 89.3–89.6%.

Economic

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

Project Summary

The S-H-U FGD unit at the Milliken Plant operated for more than 30,000 hours during the demonstration with nearly 100% availability and 90–95% SO_2 removal. Combined with LNCFS™ III low-NO_x burners which reduced NO_x emissions by 39%, the demonstrated system offers an effective option for controlling both SO_2 and NO_x for over 400 U.S. pulverized coal, tangentially fired units.

The test plan used in this demonstration was developed to cover all of the new technologies used in the project. In addition to the technologies tested, the project demonstrated that existing technologies can be used in conjunction with new processes to produce salable by-products. Generally, each test program was divided into four independent subtests: diagnostic, performance, long-term, and validation.

Environmental Performance

FGD Performance. An overall assessment of the S-H-U process is that it performed well in tests burning low- (1.6%), design- (2.2%), and high-(3.2–4.1%) sulfur (S) coals. The maximum SO_2 removal demonstrated was 98% with all seven recycle pumps operating and using formic acid, and the maximum SO_2 removal without formic acid was 95%. The unit operated routinely in the 90–95% 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% with five spray headers in service to 95.1% with all seven spray headers in service, while using a nominal 800 parts per million (ppm) formic acid concentration, a limestone grind of 90% 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% at a normal pH of 4.1 ± 0.1 to 85.4% at a lowered pH of 3.9, with all other operating conditions the same.

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 tests were performed on the full range of variables. The number of spray headers in service impacted SO_2 removal efficiency. The SO_2 removal rate ranged from a low of 30% using only two spray headers without formic acid to 98% using all seven spray headers and 800 ppm of formic acid. The maximum SO_2 removal was 98% at a 95% confidence level of ± 0.7%.

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% without formic acid to 97% with 800 ppm of formic acid added. Formic acid effects diminished with increasing concentration. Also, 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.

High-Sulfur Coal (3.2–4.1% S). Both time contraints and slurry pump capacity limited high-sulfur coal testing. Nevertheless, certain conclusions were reached as a result of those tests. As expected, 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. Indications were that an S-H-U with higher slurry pump capacity would perform at high SO_2 removal efficiencies using high sulfur coals.

Nine tests were performed using an alternative limestone grind size. Higher SO_2 removal resulted using the finer grind (90% passing through 325 mesh) limestone in lieu of the coarser grind (90% passing through 170 mesh). The average difference in SO_2 removal between the two grind sizes was 2.6 percentage points, as shown in Exhibit 3-40.

Low-NO_x Burner Performance. At full boiler load (145–150 MWe) and 3.0–3.5% 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% reduction. At a reduced boiler load of 80–90 MWe and 4.3–5.0% 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% reduction. Carbon in the fly ash was maintained below 4% 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%. This decreased to 0.12% after the modification.

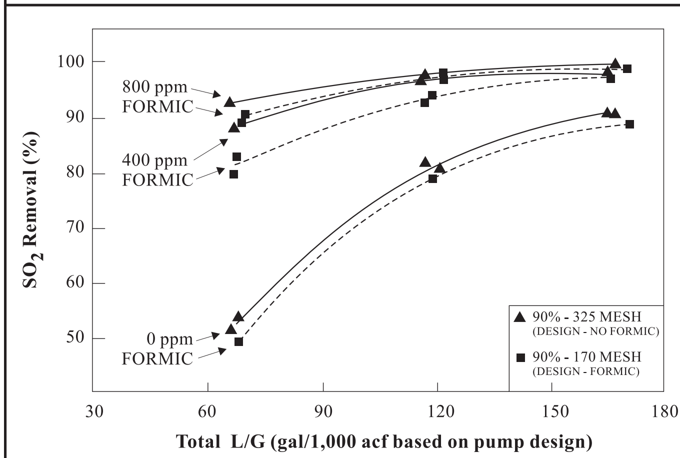
Air Toxics. Comprehensive air toxics emissions and characterization testing was carried out during the Milliken demonstration. In summary, the ESP and FGD combined to remove 99.81% of trace elements found primarily in the solid phase, with the ESP averaging 99.7% removal. The ESP removed 99.96% of the major ash elements. The ESP removal efficiency for mercury was 16.7% and the FGD removal efficiency was 59.8%.

Operational Performance

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

Exhibit 3-40

Effect of Limestone Grind



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% at capacity factors of 70–80%. Unit thermal efficiencies hovered around 35%. However, some initial problems had to be overcome and the demonstration identified some areas to improve performance in future applications.

Plugging of the slurry spray nozzles and hydrocyclone elements with rubber coming off the rubber-clad turning vanes and gypsum deposits resulting from insufficient seed crystals in the absorber slurry tank was solved by installing screens at the slurry pump intakes and keeping gypsum levels up in the absorber reaction tank. Mixing in the slurry tank was problematic and resulted in continuous operation of the slurry pumps to alleviate the problem, albeit at higher 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 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).

Low-NO_x Burner Performance. Boiler efficiency was 88.3–88.5% using LNCFS™ III, compared to a baseline of 89.3–89.6%. 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. 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% 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.

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% 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 project final report, the data was insufficient to draw any conclusions on the system.

Economic Performance

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% capacity factor using 3.2% sulfur coal and achieving 95% 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. 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 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.

Contacts

Jim Harvilla, Project Manager, (607) 762-8630
New York State Electric & Gas Corporation
Corporate Drive—Kirkwood Industrial Park
P.O. Box 5224
Binghamton, NY 13902-5224
jjharvilla@nyseg.com
(607) 762-4002 (fax)

Victor K. Der, DOE/HQ, (301) 903-2700
victor.der@hq.doe.gov

Thomas A. Sarkus, NETL, (412) 386-5981
sarkus@netl.doe.gov

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