
ABB ENVIRONMENTAL SYSTEMS

ABB ENVIRONMENTAL SYSTEMS SNOX™ FLUE GAS CLEANING DEMONSTRATION PROJECT



PROJECT PERFORMANCE SUMMARY
CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

JUNE 1999



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ENVIRONMENTAL CONTROL DEVICES

ABB ENVIRONMENTAL SYSTEMS SNOX™ FLUE GAS CLEANING DEMONSTRATION PROJECT

Applying SNOX™ to a high-sulfur, bituminous coal-fired plant resulted in 95% SO₂, 94% NO_x, and 99+% particulate emission reductions and the production of commercial grade sulfuric acid without the use of alkali reagents and without generating waste streams.

OVERVIEW

A catalyst-based, high-capture efficiency system for sulfur dioxide (SO₂) and nitrogen oxide (NO_x) control, SNOX™, was successfully demonstrated at Ohio Edison's Niles Station, Unit 2, in Niles, Ohio.

The project is part of the U.S. Department of Energy's Clean Coal Technology Demonstration Program (CCTDP) established to address energy and environmental concerns related to coal use. Cost-shared partnerships with industry were sought through five nationally competed solicitations to accelerate commercialization of the most advanced coal-based power generation and pollution control technologies. The CCTDP, valued at nearly \$6 billion, has leveraged federal funding twofold through the resultant partnerships encompassing utilities, technology developers, state governments, and research organizations. This project was one of 16 selected in May 1988 from 55 proposals submitted in response to the Program's second solicitation.

SNOX™ technology integrates a selective catalytic reduction (SCR) process, SO₂ oxidation catalyst, and a unique wet-gas sulfuric acid (WSA) condenser. SNOX™ demonstrated 95 percent SO₂ and 94 percent NO_x emission reductions on high-sulfur bituminous coal, without the use of an alkali reagent. During 8,000 hours of operation, 5,600 tons of commercial grade sulfuric acid was produced, purchased, and distributed. No waste streams were generated. High efficiency particulate capture occurs by the combined effect of three systems: a high-efficiency baghouse upstream of the SNOX™ system; the downstream SO₂ oxidation catalyst, which has a sticky surface; and the WSA condenser, which tends to precipitate out small particulates.

Hazardous air pollutant (HAP) testing showed that most trace elements were captured in the baghouse with the exception of boron and mercury. Selenium and cadmium, normally a problem, were effectively captured in the WSA condenser and organic compounds were oxidized by the SO₂ catalyst.

SNOX™ has the potential for producing no net increases in carbon dioxide (CO₂) emissions. Absence of an alkali reagent precludes CO₂ emissions associated reagent production and use. The process generates sufficient heat that if captured balances the SNOX™ parasitic load on the boiler.

For a 500-MWe plant firing 3.2 percent sulfur coal, the projected capital cost for SNOX™ is \$305/kW, the levelized incremental cost of power is 6.1 mills/kWh, the cost per ton of SO₂ removed is \$219, and the cost per ton of SO₂+NO_x removed is \$198 (all constant 1995 dollars). The SNOX™ system was retained for commercial service at Niles Station to process approximately 35-MWe of flue gas. A 305-MWe SNOX™ unit in Denmark and a 30-MWe unit in Sicily have been in commercial service since 1991.

THE PROJECT

The project was prompted by the state of Ohio and its utilities' desire for continued use of high-sulfur indigenous coals, and the existence of a large population of cyclone boilers in Ohio. Cyclone boilers do not lend themselves to conventional pollution control techniques. In addition to high levels of SO₂ emissions resulting from indigenous coal use, high levels of NO_x emissions are an inherent aspect of cyclone boiler use. SNOXTM has application to all boiler types and addresses both SO₂ and NO_x.

The SNOXTM process had undergone significant testing in Europe and scale-up of the individual process steps was not a concern because the components were of modular design and had been tested at full-scale. However, achieving the correct distribution of flue gas and air through the various modules remained to be demonstrated at utility scale. Also, proof was required that SNOXTM was compatible with the U.S. utility operating environment, which differs significantly from Europe in terms of coal characteristics and operating practices.

To demonstrate the technology, a SNOXTM system was installed at Ohio Edison's Niles Station to process about one-third of the flue gas from the 108-MWe Unit 2 (35-MWe equivalent). All components of the SNOXTM system were full-scale and integrated in a commercial configuration, with the exception of returning excess process heat to the cyclone boiler. Specific objectives were to: (1) demonstrate NO_x and SO₂ removals of 90 and 95 percent respectively; (2) prove the commercial quality of the sulfuric acid product; and (3) characterize the technical, environmental, and economic performance of the technology.

Both short-term parametric testing and long-term testing to evaluate operational performance were conducted. Each subsystem, as well as the full system, were assessed as outlined in *Table 1*.

Project Sponsor

ABB Environmental Systems

Additional Team Members

Ohio Coal Development Office — cofunder
Ohio Edison Company — cofunder and host
Haldor Topsoe a/s — patent owner for process technology, catalysts, and WSA tower
Snamprogetti, U.S.A. — cofunder and process designer

Location

Niles, Trumbull County, Ohio (Ohio Edison's Niles Station, Unit 2)

Technology

Haldor Topsoe's SNOXTM catalytic advanced flue gas cleanup system

Plant Capacity

35-MWe equivalent slipstream from a 108-MWe cyclone boiler

Coal

Ohio bituminous, 2.8% sulfur

Demonstration Duration

March 1992 — December 1994

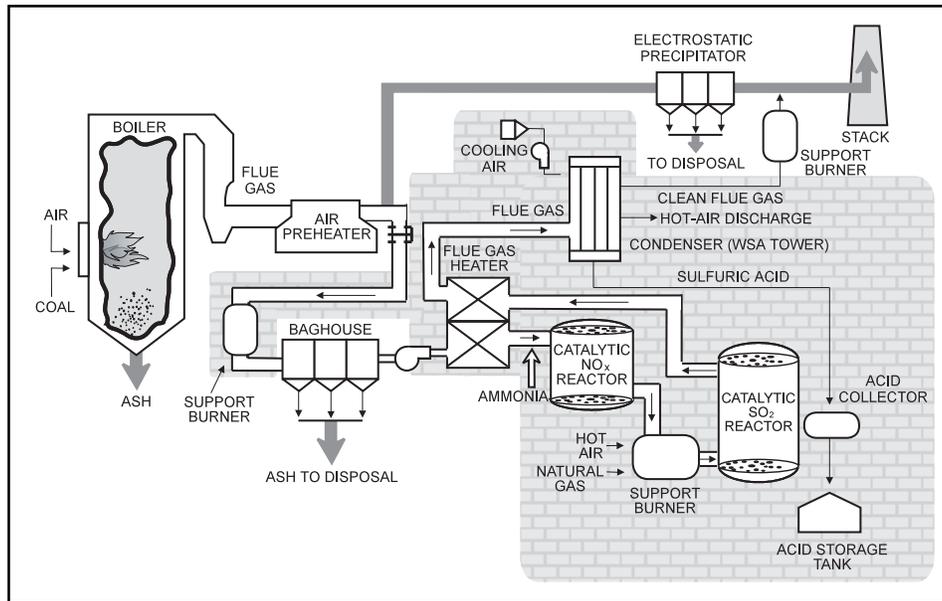
Project Funding

Total Project Cost	\$31,438,408	100%
DOE	15,719,200	50%
Participant	15,719,208	50%

TABLE 1: TEST PROGRAM

Short Term Testing		
Test Name	Variable	Range
Baseline Testing	None	Unit 2 at full load
Fabric Filter Parametric Study	Design load	75%, 100%, 110%
SCR System Parametric Study	NH ₃ /NO _x molar ratio	0.95 - 1.10
SO ₂ Converter Parametric Study	Design load Inlet temperature	80% - 110% 715° - 800 °F
WSA Condenser Parametric Study	Design load Flue gas outlet temp	60% - 110% 715° - 800 °F
Long Term Testing		
Test Name	Parameter	Range
System Performance Analysis	Design load	75%, 100%, 110%
Optimized System Tests	Design load	30% - 100%

THE TECHNOLOGY



The SNOX™ process relies on catalysis rather than reagents to affect high-efficiency capture of SO₂ and NO_x and a novel glass-tube, falling film WSA condenser to produce a salable, commercial grade sulfuric acid. A fabric filter baghouse removes flyash from the stack gas leaving the boiler. A heat pipe, gas/gas heat exchanger (GGH) heats the ash-free gas to 715 °F, and NO_x reacts with a mixture of ammonia (NH₃) and air in the presence of a selective catalytic reduction (SCR) catalyst to produce harmless nitrogen and water vapor. Downstream of the SCR, a second catalytic converter oxidizes SO₂ to SO₃. The treated gas passes through the GGH to heat the flue gas entering the reactors and proceeds into the WSA condenser where SO₃ hydrolyzes to concentrated sulfuric acid.

The incorporation of the fabric filter baghouse contributes to high-efficiency particulate capture, but its primary function is to minimize the cleaning frequency of the SO₂ oxidation catalyst. The SO₂ catalyst is in a semi-molten state, which creates a sticky surface, that results in a 90 percent particulate capture efficiency by itself. Upon particulate build-up, the catalyst is cleaned through a “screening” process conducted on-line. The baghouse reduces catalyst cleaning to once a year. The WSA condenser also contributes to particulate capture by virtue of small particulates serving as condensation nuclei.

The presence of the SO₂ oxidation catalyst downstream of the SCR allowed operation of the SCR at NH₃/NO_x stoichiometric ratios greater than 1.0 without fear of excessive NH₃ slip. Any NH₃ slip from the SNOX™ SCR is converted to water vapor, nitrogen, and a small amount of NO_x in the downstream SO₂ oxidation catalyst. This enhanced SCR efficiency relative to conventional SCRs that must keep NH₃/NO_x stoichiometric ratios under 1.0.

The SCR chemical reactions, SO₂ oxidation, hydration of SO₃, and condensation of sulfuric acid are all exothermic reactions. The heat contributes to process heat requirements and demonstrates the potential to enhance boiler efficiency to the point that the SNOX™ parasitic load could be mitigated or eliminated. Process heat is not only used to heat flue gas but to vaporize metered amounts of ammonia to reduce injection costs. In a commercial configuration, support burner heat would be required to control SCR and SO₂ oxidation catalyst inlet temperature. The bulk of process heat requirements would be met by the GGH extracting heat from the SO₂ oxidation catalyst outlet gas. The WSA condenser cooling air would collect the heats of reaction plus heat derived from the support burner and fan and send the heated air to the boiler through the air preheater. This can increase steam production on the order of 1.0 percent per each percent of sulfur in the fuel. At 2.0–3.0 percent sulfur, the recovered heat is equivalent to the SNOX™ process energy requirements.

DEMONSTRATION RESULTS

- SO₂ removal efficiency was normally in excess of 95 percent for inlet concentrations averaging about 2,000 ppm.
- NO_x emission reduction averaged 94 percent for normal operating NH₃/NO_x stoichiometric ratios of 1.02–1.05, 100 percent boiler load, and NO_x inlet levels of 500–700 ppm.
- Particulate removal efficiency for the fabric filter baghouse plus SNOX™ system was greater than 99 percent.
- Sulfuric acid purity exceeded federal specifications for Class I acid.
- HAP testing showed high capture efficiency of most trace elements in the baghouse. A significant portion of the boron and almost all of the mercury escaped to the stack. Selenium and cadmium, normally a problem, were effectively captured in the WSA condenser, as were organic compounds.
- Absence of an alkali reagent contributed to having no secondary pollution streams or increases in CO₂ emissions resulting from operation of SNOX™.
- Presence of the SO₂ oxidation catalyst virtually eliminated carbon monoxide (CO) and hydrocarbon emissions.
- Having the SO₂ oxidation catalyst downstream of the NO_x catalyst eliminated ammonia slip and allowed the SCR to function more efficiently.
- Heat from exothermic reactions captured in the SNOX™ process proved to be sufficient to offset the parasitic load associated with the process.
- All major SNOX™ process components performed essentially without problem and all auxiliary equipment problems were resolved.
- Capital cost is estimated at \$305/kW for a 500-MWe unit firing 3.2 percent sulfur coal. The levelized incremental cost was estimated at 6.1 mills/kWh or \$219/ton of SO₂ removed, or \$198/ton of SO₂ +NO_x on a constant 1995 dollar basis.

OPERATIONAL PERFORMANCE

The major process components of the SNOX™ system performed essentially without problems throughout the demonstration, but problems were experienced with auxiliary equipment.

The original gas burners providing support heat proved unstable and ultimately had to be replaced with another design (with no subsequent problems). Particular problems were experienced with the burners heating air entering the fabric filter baghouse and reheating flue gas leaving the WSA condenser and going to the stack. Malfunctions of the baghouse inlet burner caused acid deposition on the Teflon coated fiberglass (PTFE) filter bags, resulting in bag damage and contributing to poorer baghouse performance than anticipated. A new set of PTFE filter bags were installed in June 1993.

Bearing failures occurred on the flue gas booster fan. This problem was remedied by incorporating a forced lubrication system.

A discontinuity in temperature distribution was found at the GGH cold-side outlet feeding the SCR. The temperature profile showed a significant fall-off toward the wall opposite the GGH partition plate. This represented a small fraction of the flue gas mass flow, however, and the ammonia distributor, which allowed local area control, was adjusted to shut down injection in the low temperature area. (Failure to do so may have resulted in catalyst fouling from ammonia condensation.) As to the ammonia control system, the originally installed diaphragm type ammonia pump had to be replaced with a spur gear pump, which performed well.

The WSA condenser carries flue gas with low mist concentrations of sulfuric acid at sulfuric acid dewpoint temperatures. For that reason, the WSA condenser outlet duct was initially coated with epoxy. After about two years, the coating deteriorated, exposing the A36 steel ductwork. The ductwork was replaced with vinyl ester-based coated ducts, a modification performed at the 305-MWe power plant in Denmark that had proven successful.

PTFE coated fiberglass expansion joints at the SO₂ converter outlet were unable to sustain the 800°F temperatures. Replacement metal foil joints ripped soon after installation. Ultimately, an air purged joint, developed in Denmark, was installed and successfully operated.

Toward the end of the testing period, an acid leak developed at one of the inlets to the WSA condenser. This was due to flue gas leakage at the acid brick/metal flange interface, causing local acid condensation and nozzle damage. The damage was repaired and the joint resealed. A redesign of this joint was developed by Haldor Topsoe for future commercial systems.

The SCR reactor and SO₂ converter catalysts performed extremely well, suffering no physical damage and no measurable loss of performance over the demonstration. Prior experience indicated that the SO₂ converter catalyst should have required cleaning after one year even at an order of magnitude lower particulate loading than measured. But after 5,200 hours of operation, the pressure drop across the SO₂ converter was 3–4 inches of water gage, an inch below the 5 inches at which dedusting was recommended. To verify cleaning system performance, the “screening” process designed to dedust the catalyst was activated for one of the eight catalyst beds. The procedure consisted of isolating an individual bed, removing and mechanically screening the catalyst in that bed, and refilling the bed with the screened catalyst. To fully assess the screening equipment, the process, normally done hot and on-line, was conducted cold and off-line. This enabled focused, parametric analysis. All equipment performed well.

TABLE 3: PARTICLE SIZING (MICRONS)

ESP Inlet Stage	Average		
	%	CPLT	Diam.
Precutter	71.9	28.1	>10.0
0	2.4	25.7	6.61
1	3.9	21.8	6.26
2	5.4	16.4	3.82
3	5.7	10.7	2.65
4	3.6	7.1	1.37
5	1.6	5.6	0.67
6	1.6	4.0	0.44
7	2.1	1.9	0.25
Backup	1.8	0.1	<0.25

ENVIRONMENTAL PERFORMANCE

PARTICULATE REMOVAL

Results of particulate emissions tests conducted on the high efficiency fabric filter baghouse and overall SNOX™ system are shown in *Table 2* for 75, 100, and 110 percent boiler load conditions. Particle size distribution, measured at the ESP inlet but reflective of that seen at the baghouse inlet, are shown in *Table 3*, using the California Air Resources Board Method 501.

TABLE 2: PARTICULATE EMISSIONS SUMMARY

Plant Load (%)	Baghouse Inlet*		Baghouse Outlet*		System Outlet*		Removal Efficiency (%)	
	gr/dscf	lb/hr	gr/dscf	lb/hr	gr/dscf	lb/hr	Baghouse	System
75	0.529	242	0.0082	3.50	0.0049	2.88	98.5	98.8
100	0.770	450	0.0107	6.02	0.0060	4.31	98.6	99.1
110	0.530	324	0.0089	5.54	0.0026	2.05	98.3	99.4

* Baghouse inlet results are the average of six runs and baghouse outlet and system outlet results are the average of three runs.

The measured .0082–.0170 grains per dry standard cubic foot (gr/dscf) of flue gas performance of the PTFE fabric filter baghouse was not as good as the expected .0004–.0008 gr/dscf. The relatively poor performance indicated by test results, however, was not consistent with the rate of increase in pressure drop across the SO₂ converter. As mentioned previously, the SO₂ converter is an effective particulate capture device, yet pressure drops were more consistent with lower loadings than were measured leaving the fabric filter. Furthermore, particulate emission measurements at the stack were unexpectedly high given the capture efficiency of the SO₂ converter combined with the scrubbing action of the WSA condenser where small particles serve as condensation nuclei. The material caught on stack particulate run filters appeared to include sulfuric acid mist and corrosion products. The unexpectedly high particulate emissions measurements were probably in error given the particulate capture efficiencies of the fabric filter baghouse, the SO₂ converter, and WSA condenser. The most likely sources of the error were the difficulty of accurate sampling at the very low levels of particulate, the presence of acid condensation, large particles skewing test results, or all three.

NO_x REDUCTION

NO_x emission reduction occurs in an SCR reactor using a top down gas flow design with three bed levels, two of which were initially filled and one spare. The catalyst is a high activity, titanium oxide-based, monolithic type designed for operation in the temperature range of 650–800 °F and sized for an effective space velocity (volumetric gas flow divided by total volume of catalyst) of about 7500 h⁻¹.

Several benefits were derived from the SCR location:

- The post-baghouse, low-dust environment permitted use of a high specific area, low-volume catalyst; precluded the need for sootblowers; and avoided flyash contamination with ammonia.
- With the SO₂ converter downstream, the SCR operated at more efficient NH₃/NO_x stoichiometric ratios, 1.02–1.05, without fear of ammonia slip and attendant ammonia sulfate and bisulfate condensation. (Ammonia slip is oxidized to water, nitrogen and a small amount of NO_x in the SO₂ converter.) Also, SO₂ conversion to SO₃ in the SCR, normally a concern and limited to 1.0 percent for fear of acid formation, was not a concern and enabled more efficient catalyst performance. Both these factors contributed to lowering the catalyst volume requirement (a significant capital cost consideration).

Three test series were conducted with the last being the most conservative and judged to be the most representative. In this most representative test, NO_x emission reduction was measured across the SCR and the SNOXTM system as a whole. At 100 percent boiler load and 715 °F SCR flue gas temperature, the overall SNOXTM system NO_x reduction ranged from 92–94 percent for inlet concentrations of approximately 500–650 ppmv and NH₃/NO_x stoichiometric ratios of 0.9–1.05. Removal efficiencies across the SCR were generally greater than 95 percent.

Normal operating NH₃/NO_x stoichiometries for the SCR were in the range of 1.02–1.05. SNOXTM system NO_x removal efficiencies at these stoichiometries averaged around 94 percent for NO_x inlet levels of 500–700 ppmv.

Ammonia slip measured at the design NH₃/NO_x stoichiometry of 1.02 was 10–16 ppmv. SO₂ oxidation measured for the SCR under these conditions ranged from 2.7–3.8 percent.

SO₂ REDUCTION

In the SNOXTM process, SO₂ removal is controlled by the efficiency of oxidizing SO₂ to SO₃. This takes place in the SO₂ converter downstream of the SCR after heating the flue gas to about 800 °F. The SO₂ converter was comprised of eight parallel, vertical beds filled with a vanadium-based catalyst in the shape of rings 0.4 inch O.D./0.16 inch I.D. x 0.35 inch long.

Oxidation efficiency through the SO₂ converter is primarily a function of two factors — space velocity, which governs the amount of catalyst required for given flue gas flows; and gas/bed temperature, which governed the activation of the SO₂ to SO₃ oxidation reaction. This makes temperature and flow distribution through the SO₂ converter critical. Five inlet and four outlet ducts are used to produce even distribution. Tests validated the effectiveness of the design.

Parametric testing to evaluate the effects of temperature and flue gas flow rate on SO₂ to SO₃ oxidation and resultant SO₂ removal efficiency showed higher SO₂ removal efficiency as catalyst temperature increased and flue gas flow decreased.

Testing for SO₂ and SO₃ was also performed at the baghouse inlet and system outlet at 75, 100, and 110 percent boiler load conditions. Three runs were made per load condition. SO₂ removal efficiency averaged 93.8 percent for the 75 percent load condition, 95.8 percent for the 100 percent load condition, and 94.6 percent for the 110 percent load condition. *Table 4* shows the results of the three runs at 100 percent load.

**TABLE 4: SO₂/SO₃ MACS EMISSIONS
RESULTS - 100% LOAD**

Run Number	SO ₂ Baghouse Inlet	SO ₃ Baghouse Inlet	SO ₂ System Outlet	SO ₃ System Outlet	SO ₂ System Removal Efficiency (%)
	lb/hr (ppmv)				
1	1220 (1720)	5.4 (6.2)	49.4 (58)	0.33 (0.31)	95.9
2	1330 (1880)	5.9 (6.7)	58.2 (68)	0.53 (0.49)	95.6
3	1520 (2153)	5.9 (6.6)	61.9 (72)	0.45 (0.42)	95.9
Average	1356 (1917)	5.7 (6.5)	56.5 (66)	0.44 (0.41)	95.8

To complete the sulfur capture process, the high SO_3 concentration flue gas was cooled to condense the sulfuric acid. Cooling was affected in two stages. In the first stage, the gas passes through the GGH to cool the gas to about 510 °F and provides process heat to the SCR and SO_2 converter. At this temperature, most of the SO_3 is driven to hydrate with the available water to form sulfuric acid (H_2SO_4) vapor. As shown in *Figure 1*, the precooled gas then enters the bottom of the WSA condenser and flows up through the interior of borosilicate glass tube arrays as ambient air passes counter-current across the exterior of the glass tubes. Flue gas is cooled to about 210 °F and the ambient air heated to about 400 °F. As the flue gas cools, sulfuric acid vapor condenses in a film fashion on the inner walls of the tubes and drains into the acid collection trough in the bottom of the condenser. Condensation efficiency was determined to be above 99.5 percent, with corresponding $\text{SO}_3/\text{H}_2\text{SO}_4$ aerosol mist leaving the WSA condenser below 7 ppmv. This concentration was at the low end of SO_3 emissions normally emitted in the flue gas of boilers burning medium to high sulfur coal (5–20 ppmv).

The hot concentrated H_2SO_4 product (400 °F) passes through a holding tank and a water cooled tube and shell heat exchanger to allow for dilution to commercially traded concentrations, 93.2 percent by weight, at more manageable temperatures (70–100 °F).

As shown in *Table 5*, the sulfuric acid product exceeds the industry wide standard for quality as set forth in U.S. Government Specification O-S-801-E.

Arrangements were made with a sulfuric acid supplier to purchase and distribute the acid from the plant. The acid was sold to the agriculture industry for the production of diammonium phosphate fertilizer and the steel industry for pickling. Ohio Edison also used a significant amount in boiler water demineralizer systems throughout its plants.

HAP TESTING

HAP testing conducted on the SNOX™ system measured the following substances:

- Five major and 16 trace elements including mercury, chromium, cadmium, lead, selenium, arsenic, beryllium, and nickel;
- acids and corresponding anions (hydrogen chloride, hydrogen fluoride, chloride, fluoride, phosphate, sulfate);
- ammonia and cyanide;
- elemental carbon;
- radionuclides;
- volatile organic compounds;
- semi-volatile compounds including polynuclear aromatic hydrocarbons; and
- aldehydes.

Most trace elements were captured in the baghouse along with the particulate. A significant portion of the boron and almost all of the mercury escaped to the stack. Selenium and cadmium, normally a problem, were effectively captured in the acid drain. The sulfuric acid catalyst oxidized hydrocarbons and carbon monoxide (CO) to carbon dioxide and water.

FIGURE 1: WSA CONDENSER

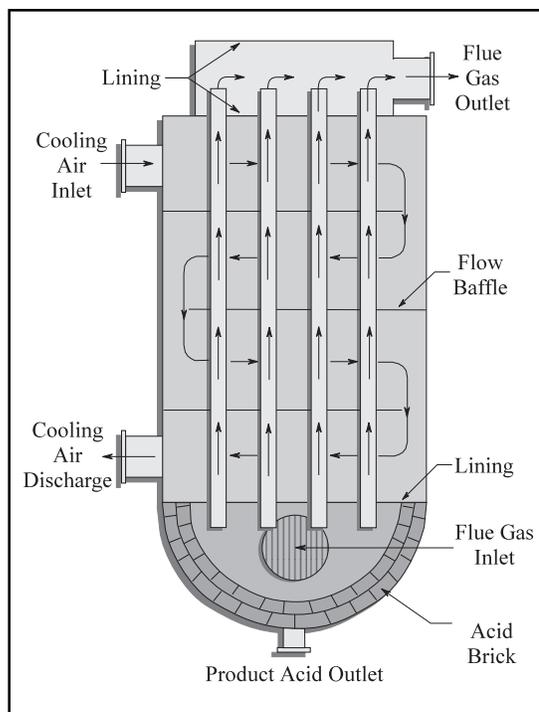


TABLE 5: NILES SNOX PLANT ACID VS. U.S. SPEC. O-S-801E

Item	Spec.	SNOX
Concentration (%)	93.2	94.7
H_2SO_3 (ppmw)	40	0.4
Iron	50	3.4
Copper	50	0.025
Zinc	40	0.12
Arsenic	1	0.012
Antimony	1	0.002
Selenium	20	0.001
Nickel	1	0.04
Manganese	0.2	0.065
Nitrate	5	2.5
Ammonium	10	2.9

CO₂ EMISSIONS

CO₂ emissions are negligible because the SNOX™ process reactions are all exothermic and no alkali reagents are used. SNOX™ avoids the release of CO₂ associated with alkali production and use (e.g., limestone and SO₂ react to release CO₂). The WSA condenser cooling air collects the heats of reaction, heat derived from the support burners and fan, and additional heat recovery from boiler flue gas (temperature taken below the usual 300 °F). If this heated air were passed through the boiler air preheater, steam production would increase on the order of 1.0 percent per each percent of sulfur in the fuel. At 2.0–3.0 percent sulfur, the recovered heat is equivalent to the SNOX™ process energy requirements.

LAND AND WATER QUALITY IMPACTS

The impact of SNOX™ on land and water quality is considered to be neutral. Absence of a solid or slurry waste precluded the need for additional waste storage or land-fill requirements. Only limited amounts of water were utilized for acid cooling and acid dilution. Cooling water does not interact with the chemical process and dilution water is consumed.

ECONOMIC PERFORMANCE

The economic assessment was based on a 525-MWe gross power plant with a net output of 500-MWe before SNOX™ installation. The SNOX™ parasitic load and net heat output were dealt with by subtracting the 12.5-MWe SNOX™ power requirement and crediting a portion of the heat put back to the boiler on a \$/10⁶ Btu basis.

The breakdown of SNOX™ system capital costs is shown in *Table 6* (constant 1995 dollars).

Particulate collection is not included because of the variability in retrofit situations and the possibility that some installations would have adequate particulate controls or require only an upgrade.

For the case presented, it is assumed that the flue gases are taken downstream of the air preheater, treated in the SNOX™ system, and directed to the stack. WSA cooling air is discharged to the boiler air preheater for combustion and for heating boiler feed water. Ammonia is received at an off-loading station and stored in ammonia tanks. Product acid is held in storage tanks until transferred through an acid loading station.

TABLE 6: TOTAL CAPITAL REQUIREMENT

Area No.	Total Installed Equipment Cost	\$10 ⁶	\$/kW
100	Raw material receiving and handling system	0.3	0.6
800	SO ₂ removal system (SO ₂ converter & WSA condenser)	22.9	45.8
900	NO _x removal system (SCR and ammonia storage & injection)	15.8	31.6
1100	Flue gas/cooling air handling system (includes GGH)	20.7	41.4
1300	H ₂ SO ₄ processing and handling system	26.5	53.0
1500	Common support systems	3.9	7.8
(A)	Total Process Capital (sum of process areas)	90.1	180.2
(B)	General facilities (10% of A)	9.0	18.0
(C)	Engineering and home office fees (10% of A)	9.0	18.0
(D)	Project contingency (25% of A+B+C)	27.0	54.0
(E)	Total Plant Cost (A+B+C+D)	135.1	270.2
(F)	Allowance for funds during construction (3.8% of E)	5.1	10.2
(G)	Total Plant Investment (E+F)	140.2	280.4
(H)	Royalty Allowance (included in catalyst/process components)	0	0
(I)	Preproduction costs (2 months of start up)	2.0	4.0
(J)	Inventory capital	1.5	3
(K)	Initial catalyst and chemicals	8.9	17.8
(L)	Subtotal Capital (G+H+I+J+K)	152.6	305.2
(M)	Cost of construction downtime	0	0
(N)	Total Capital Requirement (L+M)	152.6	305.2

TABLE 7: PERFORMANCE SPECIFICATION

Power Plant Attributes		Units	Value		
Plant Capacity, Net		MWe	487		
Power Produced, Net		10 ⁹ kWh/yr	3.84		
Capacity Factor		%	90.4		
Plant Life		yr	15		
Coal Feed		10 ⁶ tons/yr	1.72		
Sulfur in Coal		wt%	3.24		
Emissions Control Data	Units	SO ₂	NO _x	TSP	PM ₁₀
Removal Efficiency	%	95	90	99	90
Emissions without Control	lb/10 ⁶ Btu	5.76	0.69	0.37	—
Emissions with Control	lb/10 ⁶ Btu	0.29	0.07	0.004	—
Amount Removed	tons/yr	105,962	11,666	6297	—

Recovery and use of process heat is important to the economics of applying SNOX™. The magnitude of recovered heat from the process is estimated at 29.5 MWe equivalent whereas the SNOX™ power requirements is 12.5 MWe. Heat comes from the catalysts, SO₃ hydration, H₂SO₄ condensation, gas burners, and the WSA condenser lowering the flue gas temperature to about 210 °F, far lower than the 300 °F for a typical utility plant.

It is estimated that 70–80 percent of the process heat could be transferred back to the boiler because of heat losses in the flue gas and hot air ducts and the inability to use all WSA condenser outlet air under all operating conditions. An estimated 40 percent of the heat would be transferred back as high temperature combustion air and 60 percent as heat to the boiler feed water.

Estimated fixed and variable operating and maintenance costs are \$3.14 million and \$4.30 million per year, respectively. SCR and SO₂ converter catalyst life is assumed to be 10-years. Heat recovery from the SNOX™ (75 percent) is reflected as a credit, with an intermediate value between fuel replacement cost (typically \$1.50/10⁶ Btu) and what it would be worth if converted to electricity (\$4–5/10⁶ Btu).

FIGURE 2: O&M COST SENSITIVITY ANALYSIS

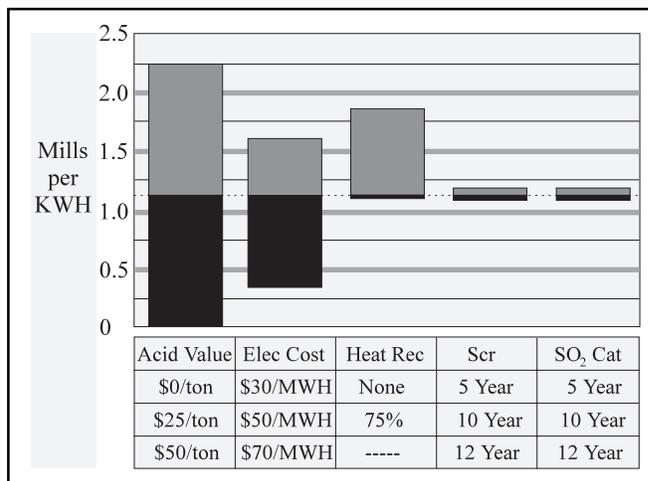


Table 7 provides the performance specification used to develop the levelized costs presented in Table 8 (constant dollars are 1995 dollars). Particulate is given as both total suspended particles (TSP) and particulate matter having a diameter of 10 microns or less (PM₁₀).

A sensitivity analysis was conducted to look at the effects acid value, electricity cost, heat recovery, and catalyst life have on operating and maintenance (O&M) costs. As shown in Figure 2, acid value, electricity cost and heat recovery had a significant impact on O&M costs while catalyst life did not.

Table 8: Levelized Costs

Levelized Cost of Power	Current Dollars		Constant Dollars	
	Factor	Mills/kWh	Factor	Mills/kWh
Capital Charge	0.160	6.36	0.124	4.93
Fixed O&M Cost	1.314	1.08	1.000	0.82
Variable Operating Cost	1.314	0.39	1.000	0.30
Total Cost	—	7.83	—	6.05
Levelized Cost–SO ₂ Basis	Factor	\$/ton removed	Factor	\$/ton removed
Capital Charge	0.160	230.5	0.124	178.6
Fixed O&M Cost	1.314	38.9	1.000	29.6
Variable Operating Cost	1.314	14.4	1.000	10.9
Total Cost	—	283.8	—	219.1
Levelized Cost – SO ₂ +NO _x	Factor	\$/ton removed	Factor	\$/ton removed
Capital Charge	0.160	207.6	0.124	160.9
Fixed O&M Cost	1.314	35.1	1.000	26.7
Variable Operating cost	1.314	13.0	1.000	9.9
Total Cost	—	255.7	—	197.5

COMMERCIAL APPLICATIONS

MARKET

As a post combustion pollutant control system, SNOX™ can be applied to all boiler types for either retrofit or new plant installations. The primary market identified is 410 existing “uncontrolled” units that are over 100-MWe in size or larger, incorporate reheat design, and were placed in service from 1955–1975, representing some 128 gigawatts (GW). More specifically, the initial focus for commercialization is an eight state region where many of these units are located — Pennsylvania, West Virginia, Kentucky, Ohio, Tennessee, Missouri, Illinois, and Indiana. This is also a region where sulfuric acid is produced from elemental sulfur.

With respect to sulfuric acid, the overall U.S. market is large relative to the acid output from a typical 500-MWe SNOX™ plant. Regional use varies and the cost of transportation becomes significant for considerable distances. For this reason, an estimated 69.8 percent of the total 42.9 million tons of sulfuric acid production per year is produced on-site and is not considered a market target for SNOX™. The balance of production, 12.9 million tons of “merchant production”, is the more realistic market. Acid production from a 500-MWe SNOX™ plant using 3.0 percent sulfur coal represents only 0.83 percent of the U.S. merchant production market.

IMPACT OF SITE SPECIFIC FACTORS

Boiler characteristics have no effect on SNOX™ performance other than size, which can introduce some negative economies of scale for smaller units. Also, steam turbine characteristics have no effect. Other factors that can have an effect are:

- **Coal type and characteristics**— Large amounts of arsenic or other catalyst poisons in the coal may reduce catalyst life; process economics favor high sulfur coal
- **Load profile**— Economics are better for a base load application
- **Geographic location**— Feasibility of shipping/selling the sulfuric acid product
- **Particulate collector**— High efficiency particulate collection required. Higher loadings affect SO₂ catalyst cleaning frequency and replacement interval, hence operating costs
- **Raw materials**— Ammonia required for the SCR

Mandatory inclusion of the SCR and high particulate removal steps in the process make it difficult for SNOX™ to compete with technologies that control SO₂ alone. But the recent EPA Rulings on ozone nonattainment and particulate control place a premium on high efficiency NO_x and particulate removal, enhancing the competitive position for SNOX™. A case study comparing SNOX™ to a wet limestone scrubber (with gypsum byproduct) and SCR (WFGD/SCR) at 385-MWe size showed favorable economics for SNOX™. For comparable control of a plant burning 2.9 percent sulfur coal and generating 0.7 lb/10⁶ Btu NO_x, SNOX™ capital and O&M costs were \$235/kW and 0.77 mills/kWh respectively, while WFGD/SCR capital and O&M costs were \$266/kW and 1.66 mills/kWh respectively.



The SCR process for control of NO_x emissions is enclosed in the structure shown on the left; the flue gas duct and fan is shown on the right next to the flue gas heater enclosure in the center



This shows the sulfuric acid condenser side of the SNOX™ system with the breather pipe on the left and the acid storage tank and load-out area on the right

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