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SNOX DEMONSTRATION PROJECT

FINAL REPORT VOLUME I: PUBLIC DESIGN

July 1996

Submitted by:

ASEA BROWN BOVERI ENVIRONMENTAL SYSTEMS

1400 Centerpoint Boulevard

Knoxville, Tennessee 37932

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ABSTRACT

The SNOX process, developed by Haldor Topsoe A/S and demonstrated and marketed in North America by ABB Environmental Systems (ABBES), is an innovative process which removes both sulfur dioxide and nitrogen oxides from power plant flue gases. Sulfur dioxide is recovered as high purity, concentrated sulfuric acid and nitrogen oxides are converted to nitrogen gas and water vapor; no additional waste streams are produced. As part of the Clean Coal Technology Program, this project was demonstrated under joint sponsorship from the U.S. Department of Energy, Ohio Coal Development Office, ABBES, Snamprogetti, and Ohio Edison.

The project objective was to demonstrate the SO_2/NO_x reduction efficiencies of the SNOX process on an electric power plant firing high-sulfur Ohio Coal. A 35-MWe demonstration was conducted on a 108-MWe unit, Ohio Edison's Niles Plant Unit 2, in Trumbull County, Ohio. The \$31 million project began site preparation in November 1990 and commenced treating flue gas in March of 1992. Testing at the site concluded in December of 1994.

The following Public Design Report has been prepared for Phase I of the SNOX Demonstration Project as described in Co-Operative Agreement No. DE-FC22-90PC89655 dated December 20, 1989. The report presents a description of the technology and design criteria for the demonstration plant including modifications and additions to the Ohio Edison Niles Station Unit 2. Pertinent drawings and a complete list of drawings are provided for information and reference.

In addition to design information, cost data is provided for the design and construction of the demonstration plant; and cost estimates are provided for startup and operating expenses of the demonstration unit. The influence of commercial site specific conditions on the design and economics of the technology are also discussed.

POINT OF CONTACT

For further information on the DOE Clean Coal Technology Demonstration of the SNOX process and/or information on the technology itself, please contact:

Donald C. Borio
ABB Environmental Systems
1400 Centerpoint Boulevard
Knoxville, Tennessee 37932
(423) 693-7550

EXECUTIVE SUMMARY

The following Public Design Report has been prepared for Phase I of the SNOX Demonstration Project as described in Co-Operative Agreement No. DE-FC22-90PC89655 dated December 20, 1989. The report presents a description of the design criteria for the demonstration plant including modifications and additions to the Ohio Edison Niles Station Unit 2 at which it is installed.

The SNOX Demonstration Project utilizes a highly efficient catalytic process that removes SO_2 and NO_x from flue gases and generates salable sulfuric acid. The integrated design of the process enables high removal efficiencies, no waste production, and increased thermal efficiency of the boiler. The Demonstration Plant is located at the Ohio Edison Niles Power Plant near Niles, Ohio in Trumbull County, situated on 130 acres along the southern bank of the Mahoning River. This power station is part of the Ohio Edison System, which serves approximately 9,000 square miles in central and northeastern Ohio and western Pennsylvania. One-third of the flue gas from the Niles Station Unit 2 boiler is treated in the process.

One of the sixteen projects selected for funding under Round II of the Clean Coal Technology Program was the SNOX process demonstration proposed by ABBES. The total project cost was projected to be \$31.4 million with the co-funders being: DOE (\$15.7 million); OCDO (\$7.8 million); ABBES and Snamprogetti (\$6.7 million); and Ohio Edison (\$1.2 million). The project was selected on September 28, 1988 and the Cooperative Agreement was signed on December 20, 1989.

The execution of the SNOX Demonstration Project is divided into three phases which span approximately sixty months. These phases are identified as follows:

- Phase I Design and Permitting
- Phase IIA: Long Lead Procurement
- Phase IIB: Construction and Start-Up
- Phase III: Operation, Data Collection, and Reporting

Site preparation and installation of foundations began in November 1990 and construction was completed in November of 1991. Equipment commissioning was conducted following completion of construction and the system was first operated on flue gas in March of 1992. Testing under Phase III was completed in December of 1994.

Originally the overall program was 48 months in length and was scheduled to end in December of 1993. A task for Site Restoration was included in Phase II-B funding in the event that Ohio Edison did not opt to retain the plant. During the second half of 1993, Ohio Edison announced that it would retain the plant, and funds that were designated for dismantling were reapportioned into the operating phase of the program for testing and system modifications.

In order to demonstrate and evaluate the performance of the SNOX process during the Clean Coal Technology Program, general operating data is to be collected and parametric tests conducted to characterize the process and equipment. The primary objectives for the SNOX Demonstration Project are as follows:

- Demonstrate NO_x and SO₂ removals of 90 and 95%, respectively
- Demonstrate the commercial quality of the product sulfuric acid.
- Satisfy all Environmental Monitoring Plan requirements.
- Perform a technical and economic characterization of the technology

The demonstration project serves to demonstrate the high performance of the SNOX technology in the North American power generation industry, i.e. with U.S. fuels and operating staff. The first and foremost objective of the project is to successfully apply the technology and proprietary equipment to a power plant firing high sulfur coal so as to confirm the capability to economically meet the pollution control needs of that market. Several supporting objectives are in place to meet this primary objective. These supporting objectives are to confirm the results achieved at the Danish pilot facility, demonstrate the marketability and economic credits of the sulfuric acid and heat energy by-products, confirm the estimated low O&M costs, and define any limitations of each piece of major equipment with respect to a utility environment.

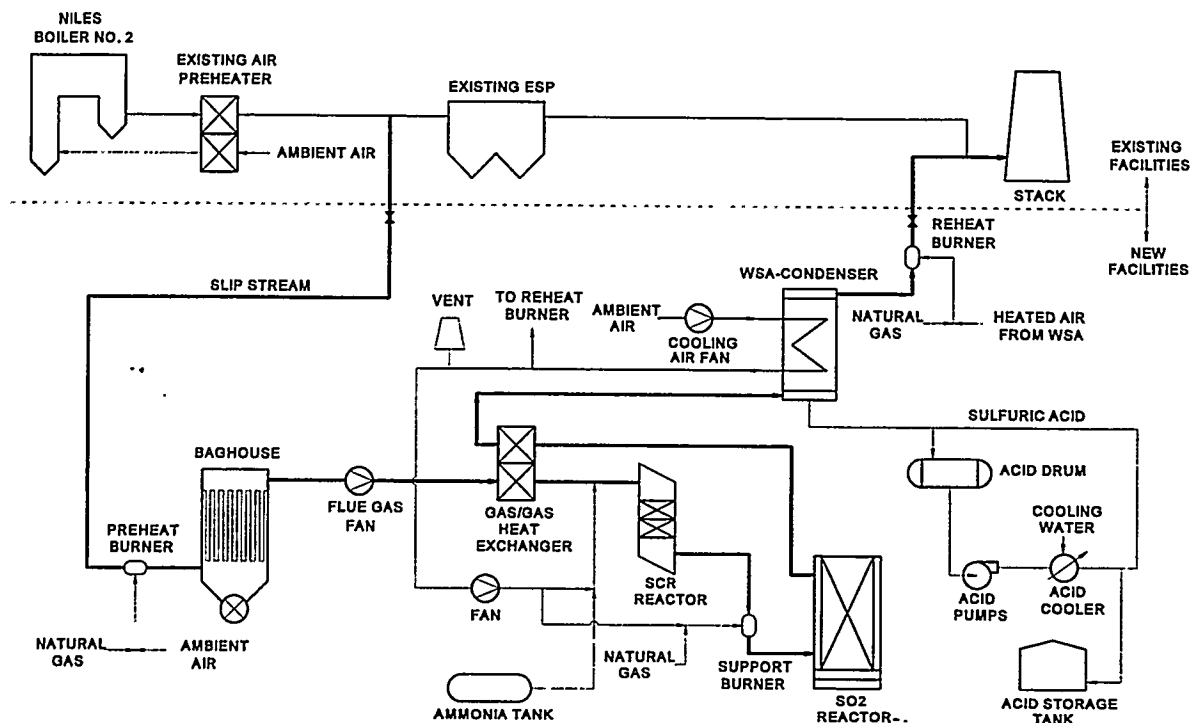


Figure 1 Niles SNOX Plant Process Flow Diagram

The SNOX technology consists of four (4) key process areas which are NO_x reduction, SO₂ oxidation, sulfuric acid (H₂ SO₄) condensation and acid conditioning. The integration of these individual steps is shown in Figure 1, which is the process flow diagram for the Niles Station.

To follow Figure 1, a slip stream of flue gas which leaves the air preheater prior to the existing electrostatic precipitator is ducted to a preheat burner and fabric filter. The preheat burner raises the temperature of the flue gas to about 400°F (204°C) to simulate a full size, integrated system wherein preheated air from the SNOX plant is fed into the boiler's air heater and would raise the outlet flue gas temperature. (The hot air at the demonstration plant is vented to atmosphere.)

After exiting the baghouse the flue gas is passed through the primary side of a gas/gas heat exchanger (GGH) which raises the gas temperature to about 730°F (388°C). An ammonia and

air mixture is then added to the gas prior to the selective catalytic reactor (SCR) where nitrogen oxides are reduced to free nitrogen and water. The flue gas leaves the SCR, its temperature is adjusted slightly by the second support burner to 780°F (415°C), and enters the SO₂ converter which oxidizes SO₂ to sulfur trioxide (SO₃). The SO₃ laden gas is passed through the secondary side of the GGH where it is cooled to 500°F (260°C) as the incoming flue gas is heated.

The processed flue gas is then passed through a falling film condenser (the WSA-Condenser) where it is further cooled to 212°F (100°C) with ambient air, below the sulfuric acid dewpoint. Acid condenses out of the gas phase on the inside of the glass tubed condenser and is subsequently collected, cooled, diluted, and stored. Cooling air leaves the WSA-Condenser at over 400°F (200°C) and is primarily vented at the Niles plant, although a small amount is used for combustion air to the natural gas burners and for dilution air for the ammonia injection into the SCR. As mentioned, in a full size, integrated installation, the heated air from the condenser would be used as combustion air to the boiler.

For the SNOX Demonstration Project at Ohio Edison, equipment and facilities are installed on a 150 ft by 120 ft unoccupied area southeast of the plant building. The equipment, starting at the Unit 2 ESP inlet and traveling in the direction of flow, consists of the First Support Burner, Fabric Filter, Venturi Flow Monitor, Booster Fan, gas/gas heat exchanger, NO_x Reactor, SO₂ Converter, WSA-Condenser, and Third Support Burner. Other major equipment/components are the NH₃ Storage Tank, Acid Storage Tanks, Cooling Air Blower, and Cooling Air Discharge Stack.

Total installed equipment cost for the demonstration plant was \$14,433,790. Engineering and all other management expenses for the project totaled \$5,677,214 for Phases I and II. This results in a total plant cost of \$20,011,004.

The SNOX technology is applicable to all electric power plants and industrial/institutional boilers regardless which fuel is fired as long as NO_x and SO_x are to be removed - the process "sees" only the flue gas. The only limit is that a moderate amount of space is needed somewhat near the

boiler so that the flue gas can be economically brought to the SNOX unit, processed and returned to the stack.

1.0 PROJECT OVERVIEW

1.1 Purpose of the Public Design Report

The following Public Design Report has been prepared for Phase I of the SNOX Demonstration Project as described in Co-Operative Agreement No. DE-FC22-90PC89655 dated December 20, 1989. The report presents a narrative of the design criteria including modifications and additions to the Ohio Edison Niles Station Unit 2. Pertinent drawings and a complete list of drawings are provided for information and reference.

1.2 Brief Description of the Project

The SNOX Demonstration Project utilizes a highly efficient catalytic process that removes SO₂ and NO_x from flue gases and generates salable sulfuric acid. The integrated design of the process enables high removal efficiencies, no waste production, and increased thermal efficiency of the boiler. The Demonstration Plant is located at the Ohio Edison Niles Power Plant near Niles, Ohio in Trumbull County, situated on 130 acres along the southern bank of the Mahoning River. This power station is part of the Ohio Edison System, which serves approximately 9,000 square miles in central and northeastern Ohio and western Pennsylvania. One-third of the flue gas from the Niles Station Unit 2 boiler is treated in the process.

One of the sixteen projects selected for funding under Round II of the Clean Coal Technology Program was the SNOX process demonstration proposed by ABBES. The total project cost was projected to be \$31.4 million with the co-funders being: DOE (\$15.7 million); OCDO (\$7.8 million); ABBES and Snamprogetti (\$6.7 million); and Ohio Edison (\$1.2 million). The project was selected on September 28, 1988 and the Cooperative Agreement was signed on December 20, 1989.

The execution of the SNOX Demonstration Project is divided into three phases which span approximately sixty months. These phases are identified as follows (shown in Figure 1-1):

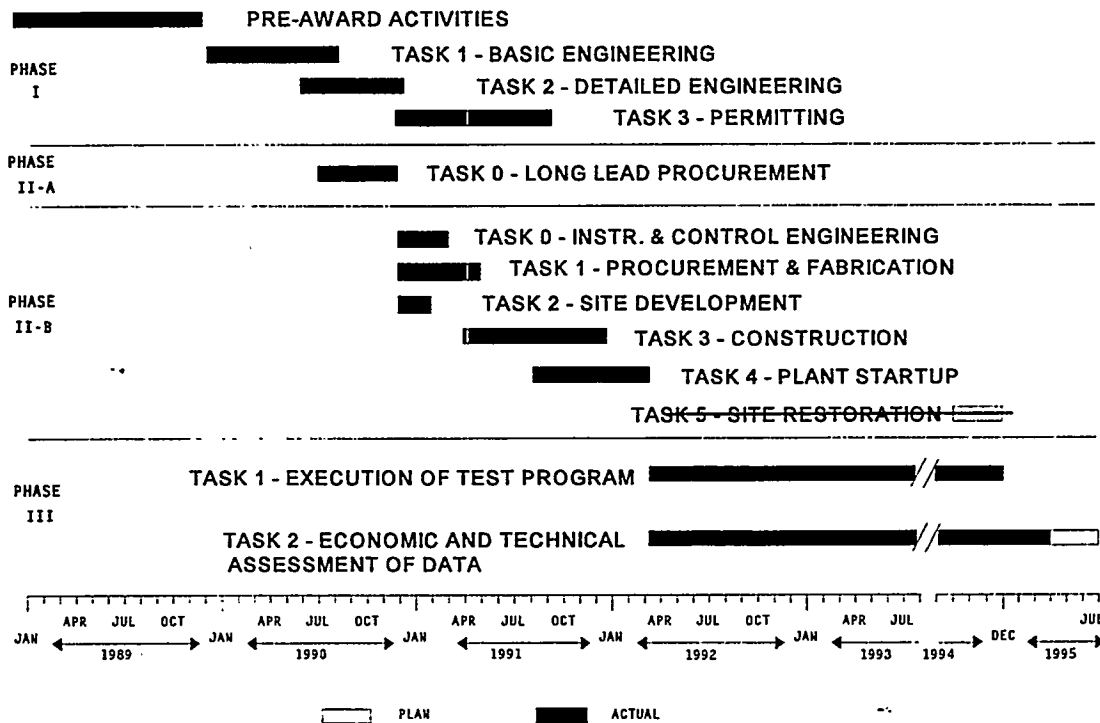


Figure 1-1 SNOX Project Schedule

- Phase I Design and Permitting
- Phase IIA: Long Lead Procurement
- Phase IIB: Construction and Start-Up
- Phase III: Operation, Data Collection, and Reporting

Phase I of this project, Design and Permitting, was further broken down into Basic Engineering, Detailed Engineering and Permitting. Basic Engineering was completed in July of 1990, followed by the completion of the Detailed Engineering toward the end of that year.

Phase IIA was comprised of the procurement of long lead time items such as the baghouse, high temperature steel, control system, gas/gas heat exchanger, and the sulfuric acid (WSA) condenser. These items were purchased at the beginning of Detailed Engineering and arrived at the Niles Plant for installation between February and May of 1991. Site preparation and installation of foundations began in November 1990 and construction was completed in November of 1991.

Equipment commissioning was conducted following completion of construction and the system was first operated on flue gas in March of 1992. Testing under Phase III of the program was completed in December of 1994.

Originally the overall program was 48 months in length and was scheduled to end in December of 1993. A task for Site Restoration was included in Phase II-B funding in the event that Ohio Edison did not opt to retain the plant. During the second half of 1993, Ohio Edison announced that it would retain the plant and funds that were designated for dismantling were reapportioned into the operating phase of the program for testing and system modifications. Part of Ohio Edison's decision to retain the plant hinged upon assurances by ABBES and DOE that existing auxiliary equipment and materials problems would be resolved. The test program was lengthened by twelve months to generate additional performance data and perform the system modifications.

Objectives of the test program were to fully establish a basis for the technical and economic evaluation of a commercial application of this technology. Included in the test program were:

- Parametric test batteries on all major pieces of equipment:

- Fabric Filter
- SCR System
- SO₂ Converter (catalyst)
- WSA-Condenser (sulfuric acid condenser)
- Gas/Gas Heat Exchanger
- Catalyst Cleaning Unit

- Quantify process consumptions:

- Power
- Natural Gas
- Catalysts
- Cooling Water
- Potable Water
- Ammonia

- Quantify process productions:

- Sulfuric Acid
- Heat

- Quantify personnel requirements

- Evaluate materials of construction

1.3 Objectives of the Project

In order to demonstrate and evaluate the performance of the SNOX process during the Clean Coal Technology Program, general operating data is to be collected and parametric tests conducted to characterize the process and equipment. The primary objectives for the SNOX Demonstration Project are as follows:

- Demonstrate NO_x and SO₂ removals of 90 and 95%, respectively
- Demonstrate the commercial quality of the product sulfuric acid.
- Satisfy all Environmental Monitoring Plan requirements.
- Perform a technical and economic characterization of the technology.

1.4 Significance of the Project

The SNOX Project is one of several CCT projects Ohio Edison currently has underway or has recently completed. Such experience with promising retrofit technologies that are simpler and less expensive than wet scrubbers will make acid rain compliance planning more efficient and effective for Ohio Edison.

Ohio is a high sulfur coal state and clean coal research and development is supported by government, business and labor. Ohio is one of the leading states in the consumption of coal. In 1989, the State of Ohio produced 31.4 million tons of coal and has demonstrated reserves of 19 billion short tons. Coal will likely continue to be the cornerstone of Ohio's energy supply. However, largely as a result of the Clean Air Act, the demand for Ohio-produced coal, both domestic and out-of-state, has fallen considerably since 1970.

The demonstration project will serve to demonstrate the high performance of the SNOX technology in the North American power generation industry, i.e. with U.S. fuels and operating staff. The first and foremost objective of the project is to successfully apply the technology and proprietary equipment to a power plant firing high sulfur coal so as to confirm the capability to economically meet the pollution control needs of that market. Several supporting objectives are

in place to meet this primary objective. These supporting objectives are to confirm the results achieved at the Danish pilot facility, demonstrate the marketability and economic credits of the sulfuric acid and heat energy by-products, confirm the estimated low O&M costs, and define any limitations of each piece of major equipment with respect to a utility environment.

Even though the technology had been fully characterized process-wise on pilot and prototype units prior to the contracting of the DOE project, the final scale-up to utility size required additional experience. For instance, since all major components in earlier plants had been designed in a modular fashion utilizing full-scale components, scale-up would not result in any new process problems. However, achieving the correct distribution of flue gas or air through the various module groups that existed in the WSA Condenser, SO₂ Converter, and SCR remained to be demonstrated at full scale. This final scale-up experience could be obtained through the DOE project.

The design of the DOE project was specifically aimed at demonstrating all SNOX subsystems and integrations that would be needed with a full scale installation. For example, all flue gas conditions such as temperatures, pressures, and compositions were exactly replicated and all support systems, such as the control system, ammonia supply, and product acid storage and distribution were designed and operated as with a full scale system. The only concept that could not be accommodated by the design was the integration of the WSA Condenser discharge air as preheated combustion air for the boiler. This was not possible since the project would only treat one third of the flue gas from the host boiler and would not result in a large enough quantity of combustion air. The principles involved with this integration, i.e. gas/gas heat exchanger design and preheated air for combustion, were believed to be fully understood and not crucial to the demonstration.

1.5 DOE's Role in the Project

Total project cost for the SNOX Demonstration was estimated to be \$31,438,408. The co-funders are the Department of Energy (\$15,719,200), the Ohio Coal Development Office (OCDO -

\$7,859,602), Asea Brown Boveri Environmental Systems (ABBES) along with Snamprogetti (\$6,665,606), and the Ohio Edison Company (\$1,194,000). The project was selected by the Source Selection Official on September 28, 1988, and assigned to the Pittsburgh Energy Technology Center (PETC). A multi-discipline team was assembled at PETC and ABBES respectively, which consisted of the project manager, a contract specialist, legal counsel, an environmental coordinator, a cost/price analyst, a post-award auditor, a patent counsel, a business financial advisor, and a public relations person. The project manager coordinates the activities of the team members throughout the life of the project.

2.0 TECHNOLOGY DESCRIPTION

2.1 Demonstration Plant Process Arrangement

The SNOX technology consists of four (4) key process areas which are NO_x reduction, SO₂ oxidation, sulfuric acid (H₂SO₄) condensation and acid conditioning. The integration of these individual steps is shown in Figure 2-1, which is the process flow diagram for the Niles Station. Flow stream compositions are detailed in Table 2-1.

To follow Figure 2-1, a slip stream of flue gas which leaves the air preheater prior to the existing electrostatic precipitator is ducted to a preheat burner and fabric filter. The preheat burner raises the temperature of the flue gas to about 400°F (204°C) to simulate a full size, integrated system wherein preheated air from the SNOX plant is fed into the boiler's air heater and would raise the outlet flue gas temperature. (The hot air at the demonstration plant is vented to atmosphere.)

After exiting the baghouse the flue gas is passed through the primary side of a gas/gas heat exchanger (GGH) which raises the gas temperature to above 700°F (370°C). An ammonia and air mixture is then added to the gas prior to the selective catalytic reactor (SCR) where nitrogen oxides are reduced to free nitrogen and water. The flue gas leaves the SCR, its temperature is adjusted slightly by the second support burner, and enters the SO₂ converter which oxidizes SO₂ to sulfur trioxide (SO₃). The SO₃ laden gas is passed through the secondary side of the GGH where it is cooled as the incoming flue gas is heated.

The processed flue gas is then passed through a falling film condenser (the WSA-Condenser) where it is further cooled with ambient air to below the sulfuric acid dewpoint. Acid condenses out of the gas phase on the inside of the glass tubed condenser and is subsequently collected, cooled, diluted, and stored. Cooling air leaves the WSA-Condenser at over 400°F (200°C) and is primarily vented at the Niles plant, although a small amount is used for combustion air to the natural gas burners and for dilution air for the ammonia injection into the SCR. In an integrated installation, the heated air from the condenser would be used as combustion air to the boiler.

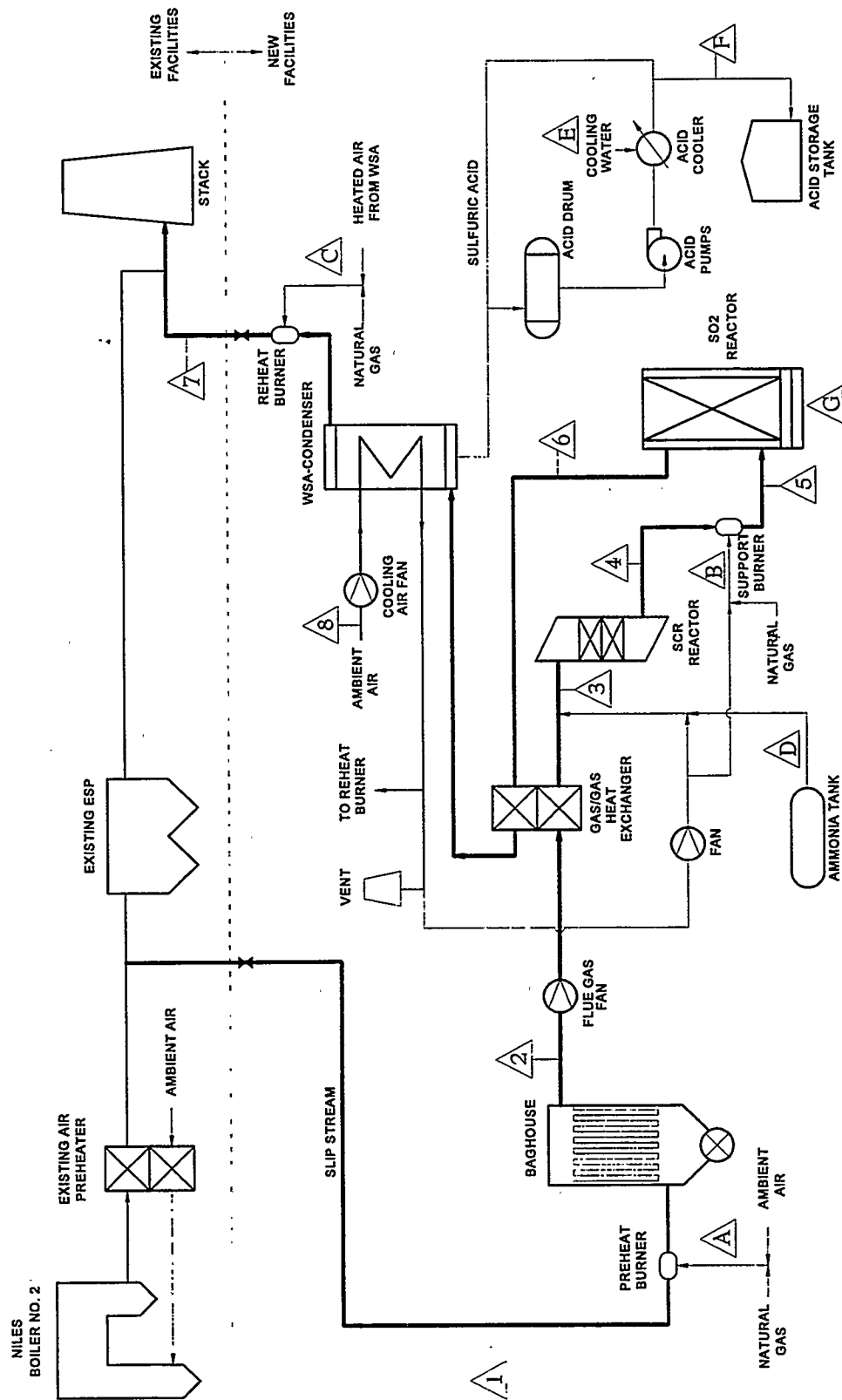


Figure 2-1 Niles SNOX Plant Block Diagram

**Table 2-1 Process Stream Flows and Compositions -
Projected Normal Operating Conditions**

Loc.	Pres.	Temp	Stream Flowrate - lbs per hour											
			O ₂	H ₂ O	CO ₂	SO ₂	SO ₃	NH ₃	H ₂ SO ₄	NOx	N ₂	CH ₄	Ash	Total
1	0	270	18530	15202	71664	1923	24			444	251224		50.000	359061
2	6	400	18682	16070	72715	1933	24			444	256612		0.300	366480
3	10	730	19512	16098	72715	1933	24	167		444	259358		0.300	370251
4	16	733	19436	16352	72715	1933	24	8		22	259614		0.300	370104
5	17	780	19547	17021	73529	1933	24	8		22	263759		0.300	375843
6	23	785	19076	17032	73529	91	2315			36	263763		0.030	375842
7	33	212	19846	17032	74621	91	12			36	271396		0.003	383034
8	atm	60	76579	2519	153						252136			331387
A	5	60	1637	62							5388	382		7469
B	5	60	1259	39							4145	296		5739
C	5	60	1701	64							5600	397		7762
D	40 psi	60							167					
E	50 psi													
F	20 psi			213										3045
G	atm												0.297	0.297

2.2 Detailed Process Information

2.2.1 Particulate Collection

The degree of particulate collection upstream of the reactor has a significant effect on the operating costs of this process. This correlation is due to the inherent characteristic of the SO₂ converter catalyst to collect and retain greater than 90% of all particulate matter which enters the converter. The collection of this particulate matter, over time, degrades the catalyst's SO₂ oxidation efficiency. The efficiency can, however, be restored through catalyst screening (described later). Higher dust loads therefore require more frequent catalyst screening which provides an incentive to utilize a high efficiency particulate collector upstream of the SNOX process area. A dust level of 1 mg/Nm³ leaving the collector has been targeted. A fabric filter with PTFE membrane bags has been demonstrated to achieve this very low emission level. As a consequence of both the high efficiency dust collector and the dust retention characteristics of the SO₂ converter, particulate emissions from the system are predicted to be significantly less than 1 mg/Nm³ (0.0004 gr/SCF), which is far below any current regulations or standards.

It should be noted that while a high efficiency particulate collector has benefits related to system operating costs, the economics do not require it exclusively. The Niles Demonstration Project with a fabric filter and PTFE bags is expected to require screening only once per year. Low dust levels entering the catalyst areas have an additional benefit of eliminating the capital and O&M costs associated with steam cleaning lances that may be necessary for the GGH and SCR at higher dust levels.

2.2.2 Nitrogen Oxide Reduction

After the particulate matter is collected and the temperature of the flue gas is increased to over 700°F (370°C) through the GGH, an ammonia (NH₃) and air mixture is introduced to the gas stream through a proprietary nozzle grid located upstream of the SCR. The proprietary design of the nozzle grid allows for controlled stoichiometric ratios of NH₃ to NO_x on a localized scale

over the cross-section of the SCR inlet duct. This is critical in order to optimize system NOx removal efficiency since any unreacted NH₃ which "slips" across the SCR will be oxidized to NOx, water, and N₂ in the SO₂ converter downstream. A slipstream of hot air which leaves the WSA-Condenser is used to evaporate and dilute a metered mass of ammonia. This NH₃/air mixture, which must be below 12 vol. % NH₃ to avoid an explosion hazard, is agitated with a static mixer and supplied to the distribution grid.

The flue gas/NH₃ mixture enters the SCR and contacts the Haldor Topsoe DNX monolithic catalyst which has been demonstrated to remove up to 97% + of the entering NOx. The reduction of NO follows Equation 2-1.



The small amount of NO₂ present in the flue gas is reduced similarly.

The general arrangement of the SNOX process offers one significant advantage over other SCR technologies using NH₃ in that those processes are limited to NH₃/NOx molar ratios of less than 1.0. This must be done in order to limit the NH₃ "slip" past the SCR to 5 ppm or less. Higher levels may result in ammonium bisulfate or bisulfite scaling. The NOx removal efficiency of these processes is thus limited to less than 90%. Any NH₃ slip in the SNOX process, however, is oxidized as it contacts the SO₂ converter catalyst downstream. This allows stoichiometric ratios of 1.00 to 1.05 and consequently higher NOx removal efficiencies without the adverse downstream effects of higher ammonia concentrations. Ammonium "salting" in the duct between the SCR and the SO₂ converter in the SNOX process is avoided by the high temperature in this area. Excess NH₃ slippage, however, must still be minimized in order to maximize system NOx removal due to partial oxidation of NH₃ to NO_x in the SO₂ converter downstream.

2.2.3 Sulfur Dioxide Oxidation

The SCR effluent is again heated slightly with natural gas, oil or steam to reach the optimum SO₂ converter inlet temperature and passed through Haldor Topsoe VK WSA sulfuric acid catalyst. The VK WSA catalyst belongs to Topsoe's VK sulfuric acid catalyst series which has seen wide use in the U.S. sulfuric acid industry for the past decade with a high degree of success. Without any reagents or additives, over 95% of the entering SO₂ is oxidized via Equation 2-2.



The efficiency of the Topsoe catalyst is not affected by the presence of water vapor or chlorides in concentrations up to 50% and several hundred ppm, respectively.

Due to surface fouling by flyash, the SO₂ converter catalyst requires screening to maintain oxidation efficiency at a frequency dependent on the removal efficiency of the particulate collection device upstream. The required screening frequency will range from once every two weeks to once a year. Regardless of the efficiency of the particulate collector, however, virtually all remaining particulate is retained in the SO₂ reactor which results in the inherently minimal particulate emissions of this process and necessitates catalyst screening on some regular basis.

The screening procedure consists of the isolation of an individual catalyst bed, removal and mechanical screening of the catalyst in that bed, and refilling the bed with the screened catalyst. Beds are sequentially screened in this manner. The procedure can be automated and is performed while the process is on-line. This procedure separates and removes virtually all flyash and other contaminants from the surface of the catalyst pellets and restores SO₂ oxidation efficiency. Catalyst loss during screening is estimated at 2-3%.

An additional benefit of the sulfuric acid catalyst is its ability to oxidize carbon monoxide (CO) and hydrocarbons present in the flue gas stream to carbon dioxide and water. This is of importance since hydrocarbons and CO emissions have come under increased scrutiny as

evidenced by the recent passage of the Clean Air Act amendments.

2.2.4 Sulfuric Acid Condensation

The SO₃ in the gas leaving the SO₂ converter is hydrated and condensed in two steps. First, the bulk of the SO₃ is hydrated to sulfuric acid vapor (Equation 2-3) as the flue gas passes through the secondary side of the GGH and drops approximately 300°F (170°C).



At this point the flue gas is still well above the acid dewpoint thus avoiding acid condensation and corrosion of the ductwork. The flue gas is then passed through the proprietary WSA-Condenser developed by Haldor Topsoe where the gaseous H₂SO₄ is converted to liquid H₂SO₄ according to Equation 2-4. The WSA-Condenser is a unique tube and shell falling film condenser with ambient air used as a cooling medium on the shell side. Proprietary borosilicate glass tubes are used to



convey and cool the flue gas. There are several features of these tubes which make possible the virtually complete condensation and capture of the sulfuric acid at concentrations of 94 to 97 wt.%. The flue gas is cooled to about 212°F (100°C) at the outlet of the condenser which combined with the presence of approximately 5 ppm of uncollected sulfuric acid mist, will require the downstream ductwork and stack to be lined. The condensed sulfuric acid product is funneled through an acid brick lined trough at the bottom of the WSA-Condenser into the acid conditioning and storage system.

The WSA-Condenser's discharge cooling air represents the only other by-product of the SNOX process. In an integrated system, the bulk of this heated ambient air at about 400°F (200°C) will be passed through the furnace air preheater and used as combustion air. A small percentage of the product air is used for system auxiliaries such as ammonia evaporation and dilution, natural

gas burner combustion air, and catalyst screening equipment heatup. The WSA-Condenser, in effect, collects the heat released from the reactions in the SCR and SO₂ converter, the hydration of SO₃, the condensation of H₂SO₄, the support burner, the booster fan compression and the overall decrease in flue gas temperature. This results in a considerable amount of energy which can be easily utilized as preheated combustion air in the furnace to increase boiler heat rate. This, in turn, increases overall thermal output per unit of fuel.

2.2.5 Acid Conditioning and Storage Systems

The hot concentrated sulfuric acid product at about 400°F (200°C) is collected and circulated through a thermoplastic lined system consisting of a holding tank, circulation pumps, and a water cooled tube and shell heat exchanger. The purpose of this loop is to cool the acid to more conveniently manageable temperatures (70-100°F or 20-40°C) and to allow for dilution of the acid to the commercially traded concentration of 93.2 wt. %. As acid is collected in the conditioning loop, it is metered off at a rate which maintains level in the holding tank. This product acid is stored in lined carbon steel tanks prior to removal by tanker truck. Based on prototype results, the sulfuric acid produced by the SNOX process at the Niles station is expected to meet or exceed U.S. Federal Specification O-S-80C Class 1 and be commercially tradeable without limitation.

2.2.6 Heat Addition, Transfer, and Recovery

Heat addition, transfer and recovery are of significant concern in the SNOX process as they influence the economic success of the technology. The process requires heat only to trim the flue gas temperature between the SCR and the SO₂ converter in a full size, integrated installation. It is anticipated that the most efficient and cost effective source of this heat in a utility environment will be steam, however, natural gas or oil can be effectively utilized.

One major piece of equipment in the SNOX process is the gas/gas heat exchanger which allows the use of the high temperatures in the process area in an economic manner by transferring sensible heat in the treated flue gas stream to the process inlet stream. Without the recycling of

this energy, it is doubtful that the process would be economically viable. Selection of the type of heat exchanger is of concern since any leakage of flue gas across the GGH, as with a rotary-type, would bypass both reactors and result in lower measured system removal efficiencies. This effect would be proportional to the amount of leakage in these heat exchangers. A stationary-type or heat pipe GGH, however, has been researched and determined to be a superior technology for the demonstration project due to its inherent zero leakage between the two gas paths and lack of moving parts allowing maximum system performance.

The process generates recoverable heat in several ways. The two reactions via Equations (2-1) and (2-2) increase the flue gas temperature by about 22°F (12°C) per 1000 ppm of NO_x and by about 5°F (3°C) per 1000 ppm of SO₂. Energy is further released by the hydration (Equation 2-3) and condensation (Equation 2-4) of sulfuric acid. In total, sulfuric acid production yields 2.42 kWh(th) per kg (3,750 Btu/lb) of sulfur recovered as acid. The above heats plus the heat of compression generated by the flue gas booster fan and the support heat added after the SCR are recovered in the WSA-Condenser cooling air discharge for use in the furnace as combustion air. This can increase steam production on the order of 1% per each percent of sulfur in the fuel. At 2-3% sulfur, the SNOX process energy requirements are compensated.

The above characteristics make the use of high sulfur, low cost fuels economically attractive with this process. It should be noted that in a retrofit application of this technology, some modifications to the existing power block equipment will be required in order to fully benefit from the new combustion air source. First, modification of the furnace air preheater may be necessary due to the increased volume and temperature of the inlet air. Second, the increased boiler heat rate may require additional tube banks in the boiler if the design fuel feed rate is to be maintained. Of course, the thermal output of the boiler will increase accordingly.

3.0 PROCESS DESIGN CRITERIA

The following table lists the design specifications for the SNOX Demonstration Project.

Table 3-1 Design Specifications

Inlet Flue Gas Conditions:	<u>Units</u>	<u>Design Operation</u>	<u>Operating Range</u>
Flow (@ Baghouse)	scfm	78,000	39,000-78,000
Temperature	°F	305	260-350
Pressure	in. w.g.	0.25	0.25-0.75
Particulate	gr/dscf	10.0	7.5-12.5
Sulfur Dioxide	ppm	3500	1500-3500
Nitrogen Oxides	ppm	900	700-900
Outlet Flue Gas Conditions:			
Flow (to Stack Breaching)	scfm	82,000	41,000-82,000
Temperature	°F	302	300-400
Pressure	in. w.g.	0.0	-0.5-0.5
Particulate	gr/dscf	~0	~0
Sulfur Dioxide	ppm	175	75-175
Nitrogen Oxides	ppm	90	40-90
Sulfuric Acid Product:			
H ₂ SO ₄ Content	wt. %	93.2	93.2-94.2
Iron	ppm	20.0	10.0-50.0
Clarity (APHA Standard)	Color	15.0	10.0-30.0
Natural Gas:			
Supply Pressure	psia	150	150
Sulfur Content	%	0	0
Cooling Water:			
Supply Pressure	psig	90	90
Supply Temperature	°F	60	34-84
Max. Temperature Increase	°F	18	-

Table 3-1 Design Specifications (Cont'd)

	<u>Units</u>	<u>Design Operation</u>	<u>Operating Range</u>
Anhydrous Ammonia:			
NH ₃ Content	wt. %	99.7	99.5-99.99
Oil	ppm	1.2	0.1-5.0
Climatic Conditions:			
Temperature	°F	60	-20-100
Barometric Pressure	in. w.g.	395.5	385.5-405.5
Relative Humidity	%	70	60-83
Noise Level:			
Maximum @ 3 ft.	dB(A)	85	
Coal:			
Carbon	%	63.37	
Hydrogen	%	4.63	
Oxygen	%	6.65	
Nitrogen	%	1.07	
Sulfur	%	3.76	1.6 - 3.76
Water	%	7.58	
Ash	%	12.94	
HHV	Btu/lb	11,600	

The Process Flow Diagram for the design conditions for the SNOX Demonstration plant is shown in Figure 3-1.

In order to adequately design a SNOX system from a process standpoint, the information listed in Table 3-2 is required for the major process areas.

Table 3-2 Process Design Criteria

PROCESS AREA	DESIGN CRITERIA	INFORMATION
Flue Gas Handling	Flue Gas Inlet Flow Rate	Volumetric @ Temperature
	Pressure Drop	Flange to Flange
	Particulate Removal	Efficiency
NO _x Removal	NO _x Removal	Percent Reduction
	Catalyst Volume	Space Velocity
	Reagent Feed Ratio	NH ₃ /NO _x Molar Feed Ratio
	Vessel Gas Rate	Superficial Gas Velocity
SO ₂ Removal	SO ₂ Removal	Percent Reduction
	Catalyst Volume	Space Velocity
	Vessel Gas Rate	Superficial Gas Velocity
Acid (H ₂ SO ₄) Condensation	Vessel Gas Rate	Superficial Gas Velocity
	Cooling Air	Flue Gas Flow, Δ T
	Cooling Air	Acid Production Rate
Acid Conditioning	Acid Cooler	Acid Production Rate
	Dilution Water	Acid Concentration
Balance of Plant	Ammonia Tank	Storage Time
	Acid Tank	Storage Time

4.0 DETAILED PROCESS DESIGN

4.1 Plot Plan and Plant Layout Drawing

For the SNOX Demonstration Project at Ohio Edison, equipment and facilities are installed on a 150 ft by 120 ft unoccupied area southeast of the plant building as shown in the SNOX Demonstration Plant General Arrangement drawing, Figure 4-1. The equipment, starting at the Unit 2 ESP inlet and traveling in the direction of flow, consists of the First Support Burner (H-201), Fabric Filter (A-202), Venturi Flow Monitor (V-101), Booster Fan (K-203), GGH (E-204), SCR (R-206), Second Support Burner (H-207), SO₂ Converter (R-208), WSA-Condenser (E-209), and Third Support Burner (H-210). Also shown are the NH₃ Storage Tank (B-225), Acid Storage Tanks (B-223 A/B), Cooling Air Blower (K-230), and Cooling Air Discharge Stack (S-270).

4.2 Major Plant Process Areas

4.2.1 Flue Gas Conditioning and Dedusting System

The primary purpose of the Flue Gas Conditioning System is to increase the temperature of the inlet flue gas slipstream, to better simulate the conditions of a full-scale application of the SNOX Process, and to filter the flue gas for particulate (the P&ID for this section is shown in Figure 4-2). Inlet flue gas to the SNOX Demonstration Plant is conditioned in two steps prior to entering the catalytic process block. First, the flue gas passes across the 1st Support Burner (H-201) to increase its temperature to about 385°F. The temperature prior to the burner is between 260 and 350°F. After preheating, the flue gas is filtered for particulate in a pulse jet baghouse (A-202). A high degree of particulate removal is necessary for obtaining long running times between SO₂ oxidation catalyst screening and high sulfuric acid purity. The filter material used in the baghouse has a maximum operating temperature (475°F) which is interlocked with the control of H-201. As flyash is collected from the flue gas and deposited into the baghouse hoppers, each hopper is sequentially evacuated by the flyash removal system. The ash removal system is integrated with the pre-existing Electrostatic Precipitator (ESP) ash evacuation system.

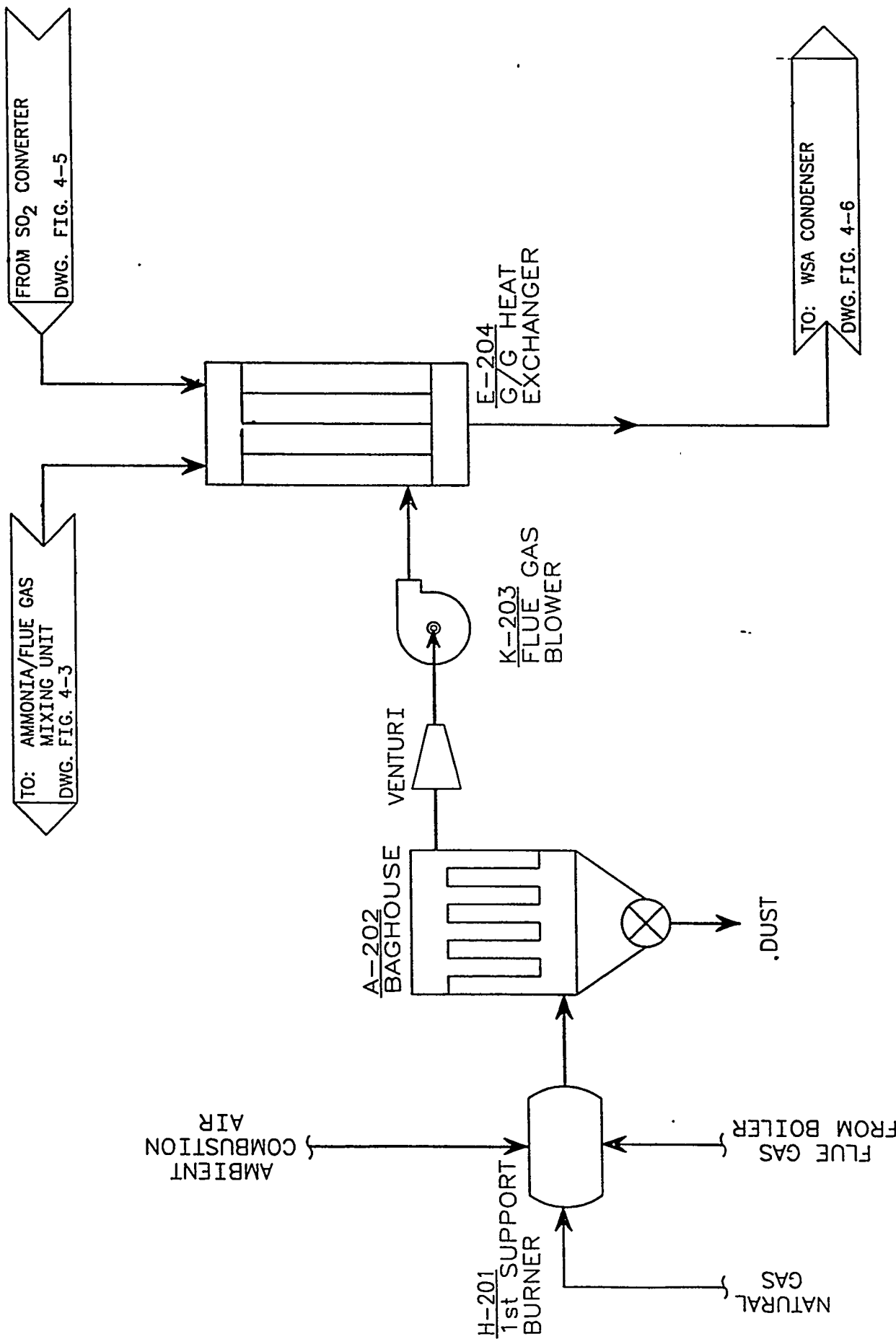


FIGURE 4-2
 FLUE GAS DEDUSTING

Inlet Damper (ZCV-0100) The Inlet Damper is a 6' x 6' carbon steel EFFOX guillotine damper with seal air. This damper is positionable throughout the open-closed range and is zero-leak. The Inlet Damper is controlled by the Distributed Control System or DCS through a forward/reversing motor starter in the motor control center, or MCC. The DCS receives a continuous position feedback 4-20 mA signal representing 0-100% open. Limit switches are provided to inform the DCS of an open or closed damper. Seal air is provided by a continuous operation seal air blower. The seal air pressure is locally indicated with a pressure gauge and a switch alarms low seal air pressure.

Inlet Vent Damper (ZCV-0120) The Inlet Vent Damper is a positionable double wafer damper by EFFOX with seal air. The seal air fan is common to both ZCV-0120 and ZCV-0100. This damper is also zero-leak. The Inlet Vent Damper is controlled by the DCS through a forward/reversing motor starter in the MCC. The DCS receives a continuous position feedback 4-20 mA signal representing 0-100% open. Limit switches are provided relaying 120VAC to inform the DCS of an open or a closed damper. Seal air is provided by a continuous operation seal air blower which also serves the Inlet Damper. The seal air pressure is locally indicated by a pressure gauge and a low pressure switch relays 120VAC to inform the DCS of low seal air pressure.

1st Support Burner (H-201) This burner is provided by Forney and is a center fired natural gas burner with a maximum heat input rate of 15 MMBtu/h. The H-201 system contains its own independent control system for automatic start-up and shutdown. Ambient air is used for combustion air and is provided by a blower mounted at grade. The 1st Support Burner inlet temperature is measured and recorded by the DCS, as is the inlet pressure. The outlet temperature is also sensed and recorded by the DCS. This outlet temperature is the feedback control variable to the DCS for modulating the burner's heat input. The DCS provides the local burner control panel with a 4-20 mA signal corresponding to 0-100% burner load. The local burner control panel controls the fuel and combustion air flows to achieve the desired output temperature and provides local safety protection. The burner is capable of automatic control by the DCS or manual control. The burner is started through the DCS with a 120VAC signal to the

local control panel start relay. The local control panel relays back a 120VAC signal representing "Burner Flame On/Off".

Baghouse (A-202) The baghouse is provided by ABB Environmental Systems, Knoxville, and is a six-compartment pulse jet type with PTFE coated fiberglass bags. There are 1596 total bags yielding a gross air-to-cloth ratio of 3.79 FPM. The bags are 6" in diameter by 14' 1-1/4" long on 8" centers. The target emission rate of this baghouse is 0.0004 grains of particulate per dry standard cubic foot (gr/DSCF).

The baghouse is controlled independently by the Baghouse Control Panel which is located in the control room. There are three principal areas of control:

- Module Isolation
- Cleaning
- Hopper Heating

The DCS receives the Baghouse Differential Pressure from the control panel as a 4-20 mA signal. This signal represents 0-10" w.c. of pressure drop and the cleaning cycle maintains a setpoint of 5" w.c.. Hopper heating is controlled by the local Hopper Heater Control Panel.

A Broken Bag Detector is mounted in the outlet duct of the baghouse. The DCS receives a 4-20 mA signal from the Broken Bag Detector corresponding to the number of grains of flyash per cubic foot of flue gas.

The 1st Support Burner Outlet Temperature Element transmits the baghouse inlet temperature to the DCS. The Venturi Inlet Temperature Element transmits the baghouse outlet temperature to the DCS. With both inlet and outlet temperatures, the temperature difference across the baghouse is calculated. This calculated difference is used to detect any fires in the baghouse.

Gas/Gas Heat Exchanger (E-204) The primary purpose of the Gas/Gas Heat Exchanger (E-204) is to transfer sensible heat from the high temperature SO₂ Converter exit stream to the low

temperature process block inlet stream. Flue gas leaves the Booster Fan (K-203) and passes through the primary or cold side of the Gas/Gas Heat Exchanger (GGH). In this manner, the process block inlet stream is heated to allow adequate reaction rates in the catalyst beds of the process block. This process block inlet stream must be within certain temperature boundaries to protect the SCR catalyst. At temperatures below this range, ammonium compound scaling may occur. Above this temperature range, thermal deactivation of the catalyst may occur. The heat energy which is transferred to the inlet stream comes from the SO₂ Converter exit stream which passes through the secondary or hot side of the GGH prior to entering the WSA-Condenser.

The GGH used in this application is an ABB Air Preheater Company heat pipe, or Q-pipe, heat exchanger. The design allows heat transfer without rotating equipment and without leakage between the two gas paths. Any leakage from the primary side to the secondary side would result in a bypass of the two reactors and decrease system removal efficiency for both SO₂ and NO_x. The GGH provided contains 1026 heat tubes - each filled with about 3 gallons of naphthalene. Most of the tubes are constructed of carbon steel while the last five rows on the hot side are constructed of an alloy material as a protection from any minor condensation of H₂SO₄ that may occur.

The untreated, cold side flue gas inlet of the Gas/Gas Heat Exchanger is monitored for temperature and pressure. The flue gas exiting the cold side is monitored for temperature and pressure also. The flue gas exiting the hot side is monitored for temperature. The skin temperature of one heat transfer tube is monitored to ensure that no sub-dew point metal temperatures exist. To avoid acid condensation, the tube skin temperature must be greater than 400°F. This temperature is controlled by the 1st and 2nd Support Burners.

4.2.2 Nitrogen Oxide Reduction System

The primary purpose of the Nitrogen Oxide Reduction System is to efficiently react injected ammonia with the nitrogen oxides in the flue gas to form free nitrogen, water, and heat. The P&ID for this section is shown in Figure 4-3.

X-202
AMMONIA/FLUE GAS
MIXING UNIT

FROM: GAS/GAS HEAT
EXCHANGER
DWG. FIG. 4-2

R-206
SCR

H-207
2nd SUPPORT
BURNER

X-240
AMMONIA/AIR
MIXING UNIT

TO: SO₂ CONVERTER
DWG. FIG. 4-5

NATURAL
GAS

FROM: BOOSTER AIR
BLOWER
DWG. FIG. 4-5

FIGURE 4-3
NOX REDUCTION

Gas/Gas Heat Exchanger (E-204) primary discharge is injected with evaporated, diluted ammonia before entering the SCR (R-206) where the catalytic reduction of nitrogen oxides takes place. Liquid ammonia is stored in the Ammonia Storage Tank (B-225). The pressure in the tank corresponds to the vapor pressure of the ammonia at the existing ambient temperature.

Ammonia is pumped from the storage tank to the Ammonia Atomizer by the Ammonia Pump at a sufficiently high pressure to avoid two-phase flow. The liquid ammonia is atomized through the injection valve into a stream of hot air at approximately 400°F, whereby the ammonia evaporates. The flow of ammonia is adjusted by a control loop based on an NH₃/NOx stoichiometric ratio set point, the measured inlet flue gas flow, and the NOx concentrations at the inlet, midpoint, and outlet of the process.

The Ammonia/Air Mixing Unit (X-240) is a static mixer that ensures a homogeneous mixing of ammonia in air. The flow of the hot mixing air from the NH₃ Mix Blower (K-241) is maintained by a flow controller so that the ammonia concentration in the ammonia/air mixture does not exceed 6%. This keeps the process well below the explosion limit for ammonia in air, which is 12% (vol) NH₃. The ammonia/air mixture is injected into the flue gas via an injection nozzle grid. This grid is the Ammonia/Flue Gas Mixing Unit (X-205). The DeNOx catalyst in the SCR Reactor (R-206) reduces nitric oxides with the injected ammonia according to the previously listed reaction scheme:



A minimum 95% reduction of NOx is achieved. Heat corresponding to about 14°F of temperature rise in the flue gas is evolved. In order to obtain the required conversion of NOx, it is important that a uniform distribution of the ammonia/air mixture be achieved by the Ammonia/Flue Gas Mixing Unit and that the flow distribution of the gas reaching the DeNOx catalyst is uniform. The latter is achieved by turning vanes installed in the inlet of the SCR. The former is achieved through the design features of the injection grid.

The monolithic DeNOx catalyst is fitted into box-like elements which are mounted in modules each containing six elements. The SCR Reactor contains two beds of catalyst modules, and each bed contains fourteen modules. Provisions for an additional bed have been installed in case a later addition of DeNOx catalyst is warranted or desired. Doors have been installed above each catalyst holding grid to allow access for loading and inspection of the catalyst.

As the SCR catalyst deactivates over time, it will be necessary to take corrective measures in order to keep the NOx reduction above the desired level of 95%. This is done by adjusting the NH₃/NOx ratio. It should be noted that excess ammonia is partly oxidized to NOx in the downstream SO₂ Converter (R-208) as discussed later.

After start-up, when the catalyst activity is high, the SCR will be operated close to a stoichiometric NH₃/NOx ratio of 1.0. As the catalyst activity decreases, the NH₃/NOx ratio is increased so that the conversion is kept above 95%.

At initial start-up, two catalyst layers are installed in the SCR. When it is not possible to reach 90% system NOx conversion, an additional catalyst layer can be installed above the existing two layers. When the conversion limit once again cannot be achieved, the second catalyst layer is replaced with fresh catalyst. In this manner catalyst layers are successively replaced only after maximum utilization of the catalyst is achieved.

Ammonia Mix Blower (K-241) This is a centrifugal blower manufactured by Spencer Turbine which supplies hot air (400°F) from the WSA-Condenser cooling air discharge for the evaporation and dilution of ammonia. This fan also provides combustion air to the 2nd Support Burner and heatup air for the catalyst screening system. This fan is sized for 4,200 ACFM and 36.0 in. w.c. pressure increase.

NH₃/Air Mixing Unit (X-240) X-240 is an in-line static mixer designed and fabricated by Koch Engineering. This mixer is constructed of schedule 80 carbon steel and is 5 feet long and 12 inches in diameter.

The hot air for ammonia injection is provided by the Ammonia Mix Blower. The flow of air is measured by the Mixing Air Flow Element and transmitted as a 4-20 mA signal by the Mixing Air Flow Transmitter to the DCS. This signal corresponds to 0-1000 ACFM. The flow of air is controlled through the Mixing Air Flow Control Valve with a setpoint determined by the mass flow of ammonia and the maximum NH_3 concentration of 6% (vol). After the mixture exits the Ammonia/Air Mixing Unit, the mixture temperature is measured by the Ammonia/Air Temperature Element and recorded by the DCS. The Over-pressure protection of the mixture is provided by a pressure safety valve (PSV-0508) set for 265 psig.

NH_3 /Flue Gas Mixing Unit (X-205) X-205 is a proprietary injection grid designed by Snamprogetti, SpA. The pipes and nozzles of this system are constructed of 304 stainless steel.

Selective Catalytic Reduction Reactor (R-206) The SCR Reactor is an A-204 steel vessel which contains two beds of Haldor Topsoe DNX catalyst and a provision for a third. This vessel was designed by Snamprogetti, SpA.

The SCR Reactor is monitored for both pressure drop and inlet and outlet temperature. The Inlet Temperature Element senses the flue gas temperature at the Reactor inlet. An expected temperature increase of 14°F will occur across the SCR Reactor due to the NO_x reduction reactions. The Reactor outlet temperature is sensed by the Outlet Temperature Element. The inlet and outlet temperatures are recorded by the DCS. The differential pressure across the Reactor is monitored by the Differential Pressure Transmitter.

4.2.3 Ammonia Storage Section

Liquid (anhydrous) ammonia for SCR reactions is available at a temperature of 51°F and at a pressure of about 187 psia. It is stored in the vessel B-225 A/B and by means of pump P-230 it is sent to a spray nozzle flow control valve able to atomize the ammonia. The valve is connected with a flow controller and it is able to inject the liquid ammonia into the hot air duct coming from the WSA condenser E-209. The P&ID for this equipment is shown in Figure 4-4.

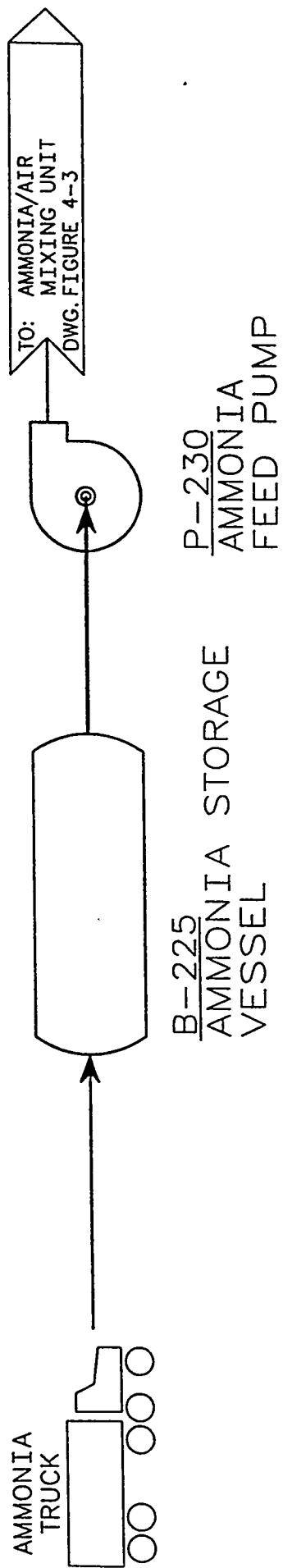


FIGURE 4-4
AMMONIA STORAGE SECTION
4-11

Ammonia Storage Tank (B-225) B-225 is a 12,000 gallon, carbon steel, ammonia storage tank manufactured by Trinity Tank. This tank volume represents a 10 to 14 day ammonia supply for the SNOX Demo Plant. The Ammonia Storage Tank is equipped with a local pressure indicator. The tank is filled through the Ammonia Inlet Valve, to which the Ammonia Transfer Truck will attach its charging pump outlet hose. The tank is to be filled until the Ammonia Storage Tank level is a maximum of 85%. The Ammonia Storage Tank Level Element and Transmitter provide liquid level measurements of 4-20 mA representing 0-100% full. Overpressure protection is provided by dual Ammonia Storage Tank Pressure Safety Valves mounted on a three-way manifold valve. The dual safety valves and three-way manifold allow for constant protection even if one of the safety valves requires maintenance.

Ammonia Pump (P-230) The Ammonia Pump is a positive displacement, diaphragm type metering pump by Chemcon. The pump is PTFE lined and is adjustable to between 0 and 48 GPH.

The Ammonia Feed Pump transfers the ammonia from the Ammonia Storage Tank to the Ammonia Atomizer. The pump outlet pressure is regulated by the Ammonia Feed Pump Outlet Pressure Regulator to 100 psi, with any excess ammonia flow being recirculated to the tank. The Ammonia Feed Pump Outlet Pressure Gauge indicates the ammonia supply pressure.

Several safety valves provide overpressure protection for the ammonia system and are set to 265 psig. The mass flow of ammonia is sensed by the Ammonia Flow Element and transmitted to the DCS by the Ammonia Flow Transmitter as a 4-20 mA signal representing 0-250 pounds per hour. The mass flow of ammonia is controlled by the DCS and is calculated from:

- NO_x signals from the Gas Analyzer (AY-1)
- flue gas mass flow signal from the Venturi (V-101)
- boiler load from Ohio Edison (QTD-0100)
- NH₃/NO_x molar ratio setpoint

The Ammonia Atomizer atomizes the liquid ammonia and controls the amount of ammonia injection based on the above calculation.

4.2.4 Sulfur Dioxide Oxidation System

The primary purpose of the Sulfur Dioxide Oxidation System is to efficiently oxidize the sulfur dioxide in the flue gas to sulfur trioxide and allow the recovery of the sulfur as sulfuric acid. The P&ID for this section is shown in Figure 4-5.

In order to obtain the optimum oxidation efficiency of SO_2 across the SO_2 Converter catalyst, the flue gas from the SCR (R-206) is heated by the 2nd Support Burner (H-207). This burner is fired with natural gas and preheated combustion air.

The sulfuric acid catalyst in the SO_2 Converter (R-208) oxidizes SO_2 in the flue gas into SO_3 according to Equation 2-2:



This reaction results in an SO_2 conversion efficiency of approximately 95%. Before entering the SO_2 Converter, the O_2 concentration of the flue gas must be more than 3.0 mole% in order to sufficiently promote the oxidation reaction. To achieve 95% SO_2 conversion for flue gas containing less than 3 mole % O_2 the catalyst volume must be increased.

The oxidation process is exothermic, and a temperature rise of 8°F is expected across the converter. Any uncombusted or partly combusted components in the flue gas, such as soot, CO and hydrocarbons are to a large extent oxidized on the catalyst. Also, any ammonia slip from the DeNOx process will be oxidized to N_2 , NOx, and water.

The catalyst is a vanadium-based oxidation catalyst in the shape of 0.4/0.16 x 0.35 inch rings. At operating temperatures, the active component will exist as a melt in the pores of the inactive carrier material. Thus, the catalyst's tacky nature will retain any remaining dust in the flue gas.

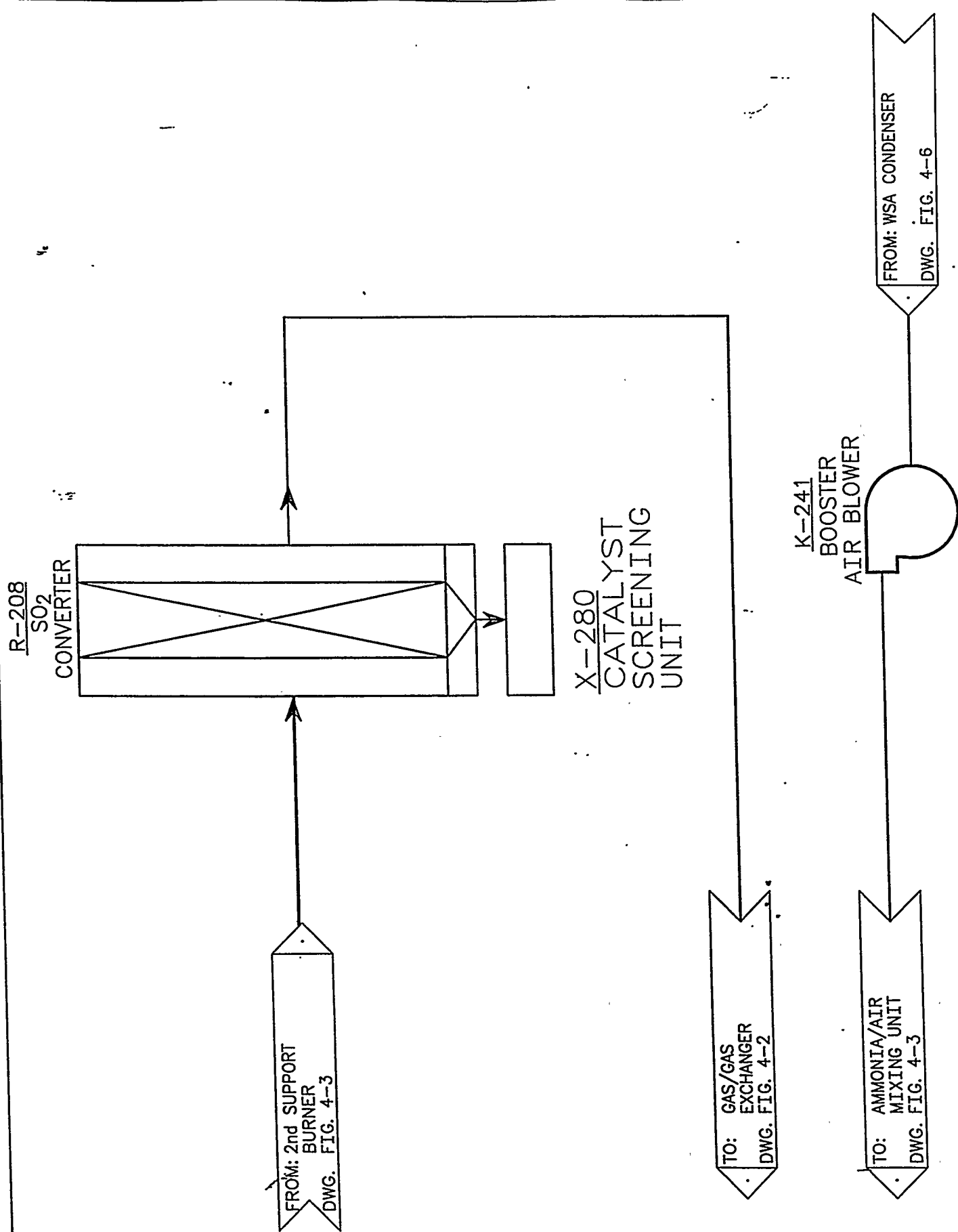


FIGURE 4-5
SO₂ CONVERSION

The SO₂ Converter consists of four catalyst panels installed in parallel, each with two vertical catalyst beds. Excess amounts of catalyst exist in the top and bottom of the converter.

The flue gas is distributed uniformly over the eight catalyst beds through five inlet nozzles. After passing through the catalyst beds, the flue gas is discharged through four outlet nozzles. Each outlet has a damper capable of stopping flow through the associated catalyst panel.

Due to the fact that the active compounds contained in the catalyst matrix are in a semi-molten state, most of the flyash entering the catalyst beds will be retained on the catalyst surface. For this reason, the catalyst must be removed from the vessel at periodic intervals to remove the flyash; the frequency of which will depend on the flyash loading. The catalyst will have a finite life and will need replacement after years of use. The useful life will depend both on the frequency of cleanings and the presence and concentration of any catalyst poisons in the flue gas such as arsenic.

2nd Support Burner (H-207) The 2nd Support Burner is a multi-flame, line burner which is natural gas fired and supplied by Eclipse Thermal Systems. This burner has a maximum heat input rate of 8 MBtu/h.

The 2nd Support Burner Inlet Temperature is measured and recorded by the DCS. The outlet temperature is also measured and recorded by the DCS. The burner outlet temperature or SO₂ Converter inlet temperature is the signal on which burner load is controlled. The DCS provides the local burner control panel with a 4-20 mA signal corresponding to a 0-100% burner load requirement. The local burner control panel controls the burner processes to achieve the desired output temperatures and provides local safety protection.

The burner is capable of automatic or manual control. The burner is started by the DCS with a 120VAC signal to the local control panel start relay. The local control panel relays back a 120VAC signal corresponding to "Burner Flame On/Off".

SO₂ Converter (R-208) The SO Converter, designed by Snamprogetti, SpA., is a vessel constructed of A-204 steel containing eight catalyst beds in parallel. The beds are filled with Haldor Topsoe VK WSA sulfuric acid catalyst. There are five inlet openings and four outlet openings. Each outlet contains a damper for panel isolation. The SO₂ Converter also has an associated Catalyst Screening Unit (X-280) which is discussed in detail in a later section.

The SO₂ Converter Inlet Pressure Transmitter sends a 4-20 mA signal to the DCS which corresponds to 0-40 " W.G. pressure. The SO₂ Converter Differential Pressure Transmitter sends a 4-20 mA signal to the DCS that corresponds to 0-7 " W.C. differential pressure across the converter. Thermowells are provided in each of the five inlet ducts for test measurements. Similarly, each of the 8 beds of the converter is equipped with two thermowells for test measurements. The SO₂ Converter has four outlet ducts. The temperature of each duct is sensed and recorded by the DCS. The four ducts combine to a single duct and the mixed gas temperature is also sensed and recorded by the DCS. The outlet ducts are equipped with manual isolation dampers. Each damper is to isolate two beds or one panel.

Catalyst Screening System (X-280) In order to dedust the SO₂ oxidation catalyst when the SO₂ Converter differential pressure reaches a maximum level and restore the normal pressure drop, the Catalyst Screening System (X-280) has been supplied. The major pieces of equipment involved in X-280 are two catalyst containers for catalyst transfer, one vibrating pan feeder to adjust the flow rate of catalyst to the screen, one vibrating screen to mechanically dedust the catalyst, one collection vessel for the catalyst sifting, and four capstan motors for catalyst container transfer throughout the system. This system is fully manual and has no control alarms or trips.

The Catalyst Screening System (X-280) is equipped with local manual control for all functions. The following motors are all started by local push button switches through the Motor Control Center.

- Feeder motor (M-710)
- Screen motor (M-720)
- Hoist motor (M-730)
- Capstan motors (M-740A, M-740B and M-740C)

Both of the Catalyst Containers are equipped with thermometers to aid in the preheat cycle described in the Catalyst Screening Procedure.

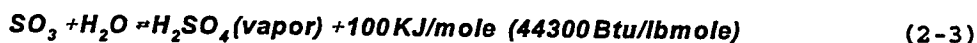
The catalyst flow into the catalyst containers is controlled by pneumatic valves, one on the bottom of each SO₂ Converter Bed. These valves are locally opened and closed by push button switches.

The Feeder Motor and the Screen Motor are interlocked such that the feeder motor cannot be started unless the screen motor is running. The Hoist Motor is equipped with both high and low position limit switches.

4.2.5 Sulfuric Acid Condensation System

The primary purpose of the Sulfuric Acid Condensation System is to cool, in a controlled manner, the process discharge flue gas so as to hydrate any remaining SO₃ and condense H₂SO₄ vapors as concentrated sulfuric acid. The P&ID is shown in Figure 4-6.

The SO₃-containing flue gas from the SO₂ Converter is cooled in the hot side of the Gas/Gas Heat Exchanger (E-204) by countercurrent heat exchange with the cooler flue gas entering the process from Flue Gas Blower (K-203). As the SO₃-rich gas is cooled, the bulk of the SO₃ is hydrated to vaporous sulfuric acid according to Equation 2-3:



In order to prevent any acid condensation and subsequent corrosion, the temperature of all metal surfaces must be above the flue gas dew point. A minimum of 20°F above the dew point is preferable.

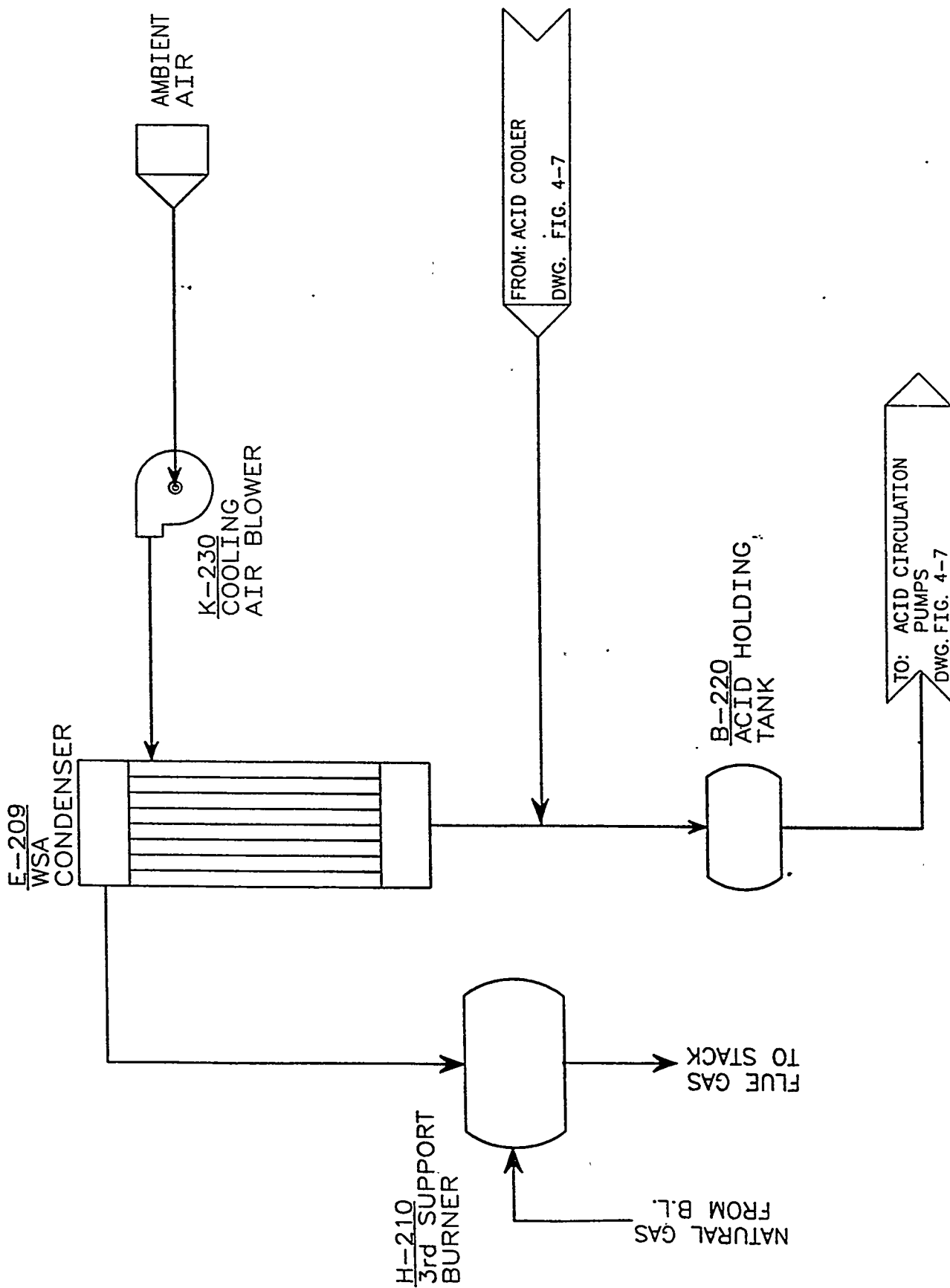


FIGURE 4-6
ACID CONDENSATION

The flue gas leaving the Gas/Gas Heat Exchanger then enters the WSA-Condenser (E-209). Here the remaining SO₃ is hydrated, the acid vapor is condensed and the flue gas is cooled to



according to Equation 2-4. The WSA-Condenser is a falling film condenser with flue gas flowing upwards in glass tubes with cooling air flowing on the shell side. The tower is divided into 10 modules each with a tube bundle consisting of 720 tubes.

Sulfuric acid condenses on the interior glass surface and is concentrated as it drains downward against the flow of hot flue gas. The product acid is approximately 400°F and 95% (w/w) H₂SO₄. The acid is collected in two semi-cylindrical brick-lined vessels running side-by-side across the bottom of the condenser. From here it is mixed with cooled sulfuric acid from the acid circulation system and enters the Acid Holding Tank (B-220).

Having passed through the WSA-Condenser, the cleaned flue gas is reheated by the 3rd Support Burner (H-210) to a temperature well above the acid dew point, 300 to 400°F, before it enters the stack breaching of the Niles Unit 2. It is also important that the WSA-Condenser be operated within a certain temperature range in order to limit the production of acid mist.

The cooling air to the WSA-Condenser (E-209) is atmospheric air supplied by the Cooling Air Blower (K-230). Cooling air is distributed through a manifold to the modules of the WSA-Condenser and becomes heated to approximately 400°F.

The WSA-Condenser's flue gas discharge temperature is regulated by controlling the cooling air flow rate. To avoid undesired high temperature differences in the top of the condenser, there is a temperature-controlled recirculation of hot air leaving the condenser to the suction side of the cooling air blower.

Some of the hot air leaving the WSA-Condenser is used for combustion air in the 2nd Support Burner (H-207) and 3rd Support Burner (H-210), mixing air for the Ammonia/Air Mixing Unit (X-240), and preheating air for the Catalyst Screening Unit. The remaining hot air is vented to atmosphere.

WSA-Condenser (E-209) The WSA-Condenser, manufactured by Snamprogetti, SpA., is a unique air cooled, falling film, tube and shell heat exchanger. The shell is constructed of carbon steel and the acid collecting bottom is PTFE coated and acid brick lined. The tubes are borosilicate glass with proprietary features for mist formation control. The flue gas discharge hoods and downstream ductwork are lined to protect against acid corrosion.

The temperature of the flue gas entering the WSA-Condenser is measured. Temperature switches are mounted in each of the inlet ducts of the condenser. These switches are used to detect sudden temperature decreases associated with sulfuric acid overflow into the inlet ducts which would indicate an acid system plug. The inlet flue gas pressure is recorded by the DCS and is represented by a 4-20 mA signal for the pressure range of 0-40 " W.G.

The flue gas exiting the WSA-Condenser is measured for temperature and is normally 212°F. This outlet temperature is controlled by the vane actuation of the Cooling Air Fan. The flue gas outlet temperature should be kept below 230°F. The outlet pressure of the flue gas is measured and recorded by the DCS through a 4-20 mA signal. This represents a pressure range of 0-40" W.G.

Cooling Air Fan (K-230) The Cooling Air Fan, manufactured by Garden City Fan, provides the ambient air that acts as the cooling media for the WSA-Condenser. This fan is of carbon steel construction and designed to provide 92,500 ACFM at 19.0 in. w.c. of head.

The cooling air flow is monitored by the Cooling Air Fan Outlet Flow Element, transmitted as a 4-20 mA signal, and recorded by the DCS. The flow varies from 0-100,000 ACFM through the modulation of the Cooling Air Fan Vane Actuator. The Cooling Air Fan Vanes are controlled

based on WSA-Condenser flue gas outlet temperature and process inlet flow. The position of the vanes is fed back to the DCS through a position transmitter.

The motor for the Cooling Air Fan is protected against over-temperature and high start frequency by a motor protection relay in the motor control center. The motor current is also monitored and indicated by the DCS.

The fan discharge air temperature is monitored and is controlled through modulation of the Cooling Air Recirculation Damper Actuator. The WSA-Condenser Cooling Air Discharge is also measured.

The fan outlet pressure is monitored and transmitted as a 4-20 mA signal corresponding to 0-30 " W.G. to the DCS.

3rd Support Burner (H-210) The 3rd Support Burner is a center-fired, natural gas burner capable of 17 MBtu/h. This burner was supplied by Forney, Inc. and uses preheated combustion air from the WSA-Condenser cooling air discharge. The purpose of this burner is to vaporize any sulfuric acid mist in the condenser flue gas discharge prior to its introduction into the pre-existing carbon steel ductwork.

The 3rd Support Burner Inlet Temperature is sensed and recorded by the DCS. The outlet temperature is also sensed and recorded. The burner outlet temperature is the feedback control variable for the burner load control loop. The DCS provides the local burner control panel with a 4-20 mA signal corresponding to 0-100% burner load. The local burner control panel controls the burner processes to achieve the desired output temperatures and provides local safety protection. The burner is started by the DCS with a 120VAC signal to the local control panel start relay. The local control panel relays back a 120 VAC signal of "Burner Flame On/Off".

Outlet Vent Damper (ZCV-0121) The Outlet Vent Damper is an EFFOX positionable double wafer damper with seal air and is zero leak. The Outlet Vent Damper is controlled by the DCS

through a forward/reversing motor starter in the MCC. Rotary drum limit switches relay 120VAC in the actuator to provide the DCS with:

- Outlet Vent Damper fully open (ZSA-0121)
- Outlet Vent Damper fully closed (ZSB-0121)

A position transmitter, sending a 4-20 mA signal from the actuator, provides the DCS with a continuous 0-100% open indication.

Seal air is provided by a continuous operation seal air blower. Seal air pressure is locally indicated with a low pressure switch.

Outlet Damper (ZCV-0108) The Outlet Damper is a zero leak guillotine damper by EFFOX with seal air. This damper is also positionable.

The Outlet Damper is controlled by the DCS through a forward/reversing starter in the MCC. Rotary drum limit switch contacts in the actuator provide the DCS with the following indications:

- Outlet Damper fully open
- Outlet Damper fully closed

A position transmitter, sending a 4-20 mA signal from the actuator, provides the DCS with a continuous 0-100% open indication.

Seal air is provided by a continuous operation seal air blower (K-0108). Seal air pressure is locally indicated with a low pressure switch.

4.2.6 Acid Conditioning and Storage System

The primary purpose of the Acid Conditioning and Storage System is to cool, dilute, and store the product sulfuric acid from the WSA-Condenser. The P&ID is shown in Figure 4-7.

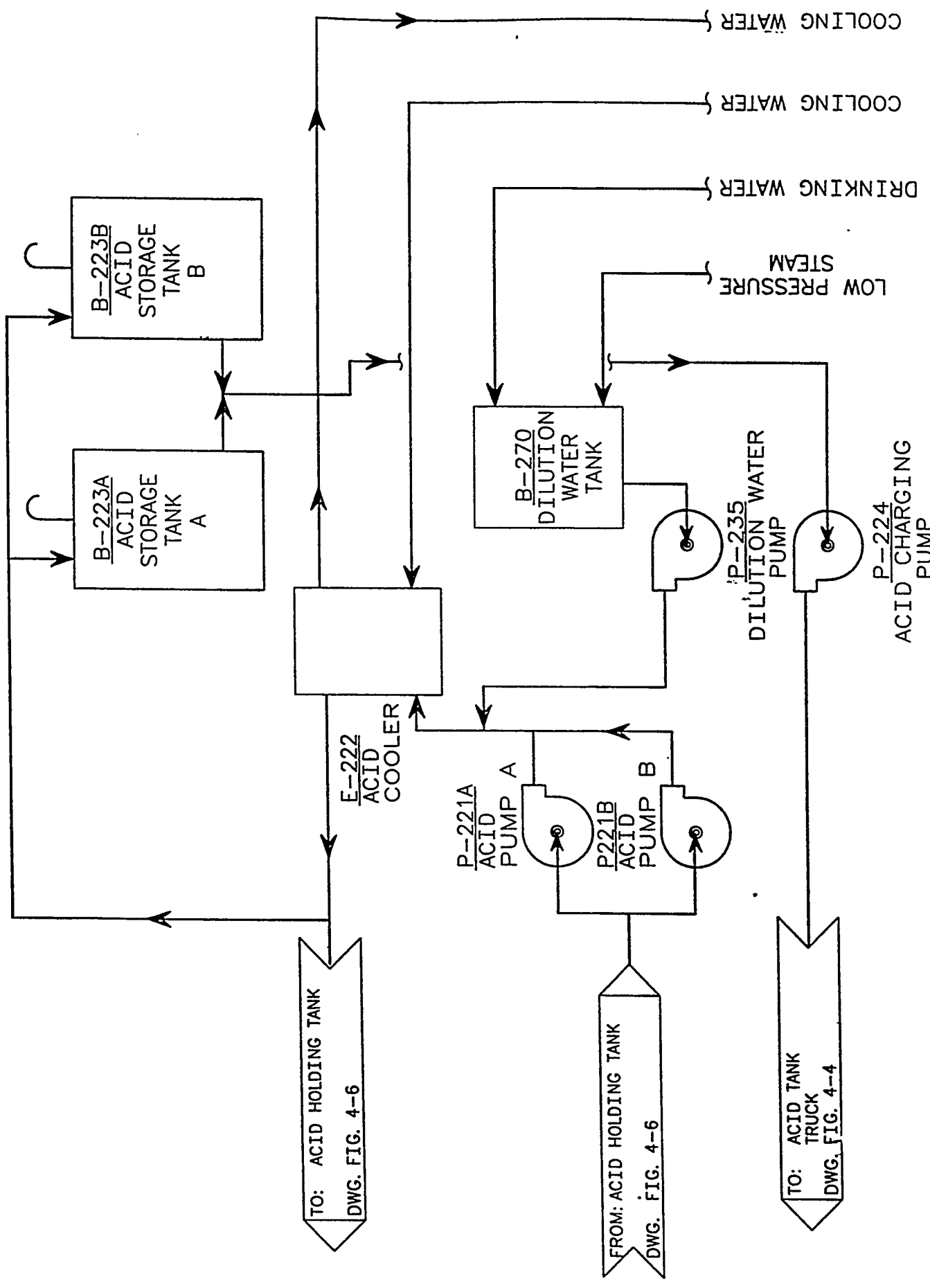


FIGURE 4-7
ACID COOLING AND STORAGE

Prior to entering the Acid Holding Tank (B-220), the hot 95 wt.% sulfuric acid from the WSA-Condenser (E-209) is mixed with cooler recirculated sulfuric acid from the Acid Cooler (E-222). The acid leaves the Acid Holding Tank (B-220) and proceeds to an Acid Pump (P-221 A or B). These pumps are one plus one spare with automatic start of the backup pump. The pump in service feeds the Acid Cooler (E-222) in which the acid is cooled with river water. After being cooled, the acid is diluted to 93.2-94.2 wt.% with potable city water. Prior to dilution, however, about 10% of the acid is diverted to the Acid Storage Tanks (B-223 A/B). The remaining acid is recirculated to the WSA-Condenser discharge and the Holding Tank (B-220).

The flow of sulfuric acid product entering the Acid Storage Tanks (B-223 A/B) is used to maintain a constant level in the Acid Holding Tank (B-220). The product acid in the storage tanks is transferred to acid tanker trucks via the Acid Charging Pump (P-224). The tanks and pump are also interconnected to allow pumping between the two storage tanks.

Acid Holding Tank (B-220) The Acid Holding Tank is an atmospheric, PTFE lined, carbon steel tank manufactured by Rapin Machinery.

The Acid Holding Tank level is measured and transmitted to the DCS as a 4-20 mA signal representing 0-100% full. The tank is also equipped with a redundant level switch that relays a 120VAC signal to the DCS upon a 70% full level. The level of acid in the tank normally ranges from 40% to 60% full with a control setpoint of 50%. The tank level is controlled by regulation of the product acid flow control valve which meters off acid from the circulation loop to a storage tank. The recirculated acid flow rate is sensed and transmitted to the DCS as a 4-20 mA signal.

Acid Circulation Pumps (P-221 A/B) The Acid Circulation Pumps are fluoropolymer lined, centrifugal, magnetic drive pumps supplied by ANSI-MAG. The dilution water flow control valve receives a 4-20 mA signal, representing a 0-5 gpm flow, from the DCS. The DCS controls the dilution water flow by sensing the acid concentration through a 4-20 mA signal. The acid circulation pumps' inlet temperature is sensed and recorded by the DCS. A temperature switch

is provided to protect the pumps from high temperature operation. The Acid Circulation Pumps are equipped with inlet and outlet isolation valves, outlet check valves, and drain valves. The pumps can only be started by the DCS through the MCC. Only one pump can be running at any time. The standby pump will automatically start on an in-service pump trip.

Acid Cooler (E-222) The Acid Cooler is a tube and shell, water-cooled heat exchanger. The wetted parts in contact with acid are constructed of Alloy 20, and those in contact with water are carbon steel. The Acid Cooler is equipped with a pressure gauge, pressure gauge isolation valve, and drain valve at the acid inlet. The acid outlet temperature is sensed and is recorded by the DCS. The water inlet is equipped with an isolation valve, temperature gauge, pressure gauge and instrument isolation valve, and a drain valve. The water outlet is equipped with a temperature gauge. The water flow through the cooler is controlled by the DCS by monitoring the acid cooler acid outlet temperature and modulating the water flow control valve with a 4-20 mA signal representing 0-100% open.

Acid Storage Tanks (B-223A&B) Tank B-223A is the main storage tank for on-spec quality product acid. The tank is 53,000 gallons in capacity, which represents a minimum storage of eight days of acid production. This tank is carbon steel with an acid resistant lining and is vented to atmosphere. This tank is supplied by McDonald Welding.

Tank B-223B is the storage tank for any off-spec acid produced during start-up or upset operating conditions. This tank is 20,000 gallons in capacity, which represents a minimum of three days product acid storage capacity. This tank is constructed of carbon steel only and is vented to atmosphere. This tank is supplied by McDonald Welding.

The acid flow to the storage tanks is controlled through the product acid flow control valve by the DCS with a 4-20 mA signal representing 0-100% open. The product acid flow is monitored and transmitted to the DCS. The storage tanks each have inlet isolation valves, outlet isolation valves, and drain valves. Acid Storage Tank A is equipped with a level element, which senses the tank level and a transmitter with local indication of level. The transmitter sends a 4-20 mA signal to

the DCS, representing 0-100% full. The off-spec tank is also equipped with a backup high-high level switch that relays a 120VAC signal to the DCS. An acid overflow drain to the containment area is provided on the off-spec tank. Tank A overflows to tank B. Both tank levels are locally indicated in the acid transfer shed.

Acid Charging Pump (P-224) The Acid Charging Pump is a fluoropolymer lined, centrifugal, magnetic drive pump supplied by ANSI-MAG. This pump is sized for 150 GPM of 93 wt.% sulfuric acid at 25.3 feet of T.D.H.

The Acid Charging Pump is operated by a local batch controller located in the transfer shed. The batch controller receives a pulse signal from a flow element counting the number of gallons of acid transferred. When the transfer limit is reached the batch controller automatically stops the pump.

Acid Containment Areas The acid storage tanks and the acid holding tank rest in two concrete containment areas. These containments are coated with an acid-resistant material. Each containment has a locally operated, submersible sump pump for the removal of collected precipitation. These pumps have local on/off switches and status indication lights with only internal interlocks and no alarms.

4.2.7 Support Systems

Air Compressors Two 100% capacity air compressors are supplied with this plant, one operating and one spare. The compressors will be piped to a common header. Each unit is controlled by an air pressure switch located on the receiver tank. Automatic backup is accomplished by offsetting the pressure switch setpoints for each unit and placing both units in automatic mode. The pressure switch for the lead operating unit should be set to start the compressor when the pressure falls to 90 psi and turn off when the pressure reaches 100 psi. The backup unit should have a lower starting pressure setpoint of 85 psi. Hence, the backup unit will start only when the operating unit fails. A low pressure switch is also provided at the discharge of each unit to alarm

compressor malfunction. These switches will be wired to a common annunciator at the baghouse control panel and will alarm "Air Compressor in Trouble."

Load Control The mass flow of flue gas, or load, being treated by the SNOX plant is measured by the Venturi Flow Monitor (V-101). A control loop in the DCS compares this measurement to a setpoint value and adjusts the position of control vanes for the Flue Gas Booster Fan accordingly. There are two pressure trips associated with this subsystem. These trips will protect the ductwork by initiating a plant trip if the pressure before the venturi drops below -20.0 in. w.g. and if the pressure after K-203 rises above +40.0 in. w.g.

Continuous Emission Monitoring System The Continuous Emission Monitoring System (CEMS) is manufactured by HORIBA. It provides SO₂, NO_x and O₂ signals at the process inlet; NO_x and O₂ signals after the SCR; and SO₂, NO_x, and O₂ signals at the WSA-Condenser outlet. These signals are used to monitor system and reactor removals of SO₂ and NO_x. The NO_x signals are also used to modulate NH₃ addition and thus control NO_x removal. All CEMS signals are continuously recorded by the DCS. A "CEMS Trouble" alarm will be displayed at the DCS on the event of any CEMS local trouble alarm.

4.2.8 Plant Modifications

Flyash Removal System The pre-existing flyash handling system serving the Units 1 and 2 precipitators at the Niles Station is a dry vacuum system furnished by the Allen Sherman Hoff Company. Vacuum is produced by one of two hydrovactors located in the Unit 2 boiler building. Flyash is sequentially and automatically evacuated from the precipitator hoppers by a control system which utilizes a Tenor drum type electromechanical controller.

The control system steps through its operation evacuating precipitator hoppers by opening and closing segregating valves and hopper dust valves that serve each branch hopper of the system. The dust valves located at each hopper are signaled to open once high vacuum is established, as indicated by vacuum switches located at the hydrovactors. These dust valves are then closed by

a signal from a low vacuum switch located at the same place, which occurs once the hopper is emptied. A water pressure switch (one for each hydrovactor) is used to indicate that adequate pressure is available to produce the required vacuum to convey flyash and signals the vacuum breaker to close.

The pre-existing system was manufactured to convey 18 tons of flyash per hour, however, the actual design capacity being conveyed is 9 tons per hour.

With the introduction of the SNOX Demonstration Project, a slip stream of 1/3 of the flue gas going to the Unit 2 precipitator is diverted to the new baghouse. The pre-existing flyash handling system was extended to convey the ash collected at the baghouse back to the main plant's disposal area. This extension is designed to convey 3.84 tons per hour of flyash. The actual flyash being conveyed will be 1.92 tons per hour. Three new air operated segregating valves were added to the system along with six new hopper dust valves. A manual isolation gate was installed at each hopper to operate the two branches of piping, each branch serving three baghouse hoppers. The third segregating valve located at the Unit 2 precipitator is used to isolate the system serving the baghouse.

Modifications to the pre-existing system were minimal. Spare positions on the tenor drum controller were used to transfer control to and from a new programmable controller (PLC) for the flyash system located with the pre-existing flyash control equipment.

The necessary high and low vacuum and water pressure control signals were extended to the new PLC from the existing hydrovactor installation. The pre-existing pressure and vacuum switches were replaced with new double contact switches. A signal from their existing control system to the new PLC indicates which of the two hydrovactors is in service.

The new baghouse hoppers are equipped with vibrators which are activated by one of two new medium-low vacuum switches installed at the hydrovactors.

To evacuate flyash from the baghouse hoppers, control is first passed to the new PLC utilizing a spare step in the existing tenor drum controllers. The segregating valves and the dust valves are all air operated with actuation triggered by signals from the PLC to solenoid control valves. Segregating valve FCV-0381 is the first valve to open and remains open until both branches of baghouse hoppers are emptied. The segregating valve serving baghouse hoppers A, C, and E opens, and once high vacuum is established at the hydrovactor end of the flyash line, the first hopper dust valve opens, allowing ash to flow from the hopper. Once ash flow begins, vacuum at the hydrovactor will decay and a second vacuum switch (medium-low) will trigger activation of the hopper mounted vibrator. The emptied hopper is detected by the low vacuum switch which activates closing of the hopper dust valve. After high vacuum is reestablished, the next hopper dust valve is opened and the process repeated. After the last hopper in the A-C-E branch has been emptied, the segregating valve for that branch closes. The second solenoid valve then opens to begin the same cycle at the B-D-F branch. Prior to closing the dust valves, the low vacuum signal triggers a 15 second delay timer to allow time for rat holes to cave in before the cycle is completed. If vacuum increases during the 15 second time period, this is an indication that rat holing has occurred. The 15 second timer is utilized up to a maximum of three (3) times to clear the hopper before passing on to the next hopper or returning control of the system to the main control system. Once the cycle has been completed at the B-D-F branch, segregating valve FCV-0381 closes and control of the ash handling system transfers back to the main control system in the plant. The main plant control panel was modified to include an indicating light to show that the baghouse ash handling system is in operation.

The control panel is furnished with a single digit indicator to show which hopper is being evacuated. A lighted graphic (mimic) panel also shows positive indication of dust valve status, monitored from limit switches furnished on each of the dust valves. The PLC panel includes manual by-pass switches to allow the operator to isolate any dust valve from operating during the cycle.

AC Electric Service AC electric service is provided to the SNOX Demonstration Plant via a single, 2.4-kV, radial feeder connected to the existing 23-kV bus in the existing Niles Station switchyard via a 6000-kVA 23-kV/2.4-kV transformer located in the switchyard.

A 34.5-kV, 1200A oil circuit breaker, located in the existing Niles Station switchyard, protects the 6000-kVA transformer as well as its 23-kV primary and 2.4-kV secondary feeders. The primary feeder consists of overhead pipe bus. The secondary feeder consists of underground cable and terminates in a 4.16-kV, 2000A, vacuum type, main circuit breaker in the 2.4-kV metal clad switchgear at the SNOX Demonstration Plant. Control of both the 34.5-kV oil circuit breaker and the 4.16-kV main circuit breaker is from the existing Niles Station control room as well as from their respective overcurrent relays. In addition, the 34.5-kV oil circuit breaker is also controlled by 23-kV and 2.4-kV differential protection relays.

The AC electric service, as installed, includes provisions for the following future modifications:

Replacement of the 6000-kVA switchyard transformer with a 10,000-kVA transformer.

Installation of four (4) cables per phase, in lieu of the two (2) cables per phase presently installed, in the 2.4-kV feeder from the switchyard transformer to the SNOX Demonstration Plant.

Connection of another electric service source to the 2.4-kV metal clad switchgear at the SNOX Demonstration Plant including the reconnection of the presently installed electric service to a SNOX Demonstration Plant 2.4-kV metal clad switchgear "cranker" bus.

DC Electric Service Electric service is provided to the SNOX Demonstration Plant via a single, 125V, radial feeder connected to a new circuit breaker at the existing main DC cabinet in the Niles Station battery room area.

The DC electric service feeder consists of underground cable and terminates at the main bus of the SNOX Demonstration Plant 125V DC circuit breaker distribution panel.

Electrical Distribution System The electrical distribution system at the SNOX Demonstration Plant consists of the following major components:

- 2.4-kV metal clad switchgear
- 480V motor control center
- 120/208V lighting and power panels
- 120V UPS system equipment and power panel
- 125V DC distribution panel

The 2.4-kV metal clad switchgear consists of 4.16-kV, draw-out, vacuum type, circuit breakers. The main circuit breaker is rated 2000A and each branch circuit breaker is rated 1200A. The branch circuit breakers' supply power to large motors and the 750-kVA 2.4-kV/480V transformer serving the 480V motor control center.

The 480V motor control center consists of a draw-out combination circuit breaker/magnetic starter for each motor load and a draw-out circuit breaker for each non-motor load. The circuit breakers used in conjunction with magnetic starters are motor circuit protector type circuit breakers. The circuit breaker used for non-motor loads are thermal magnetic type circuit breakers. A thermal magnetic main circuit breaker is provided for the incoming feeder from the 750-kVA transformer serving the motor control center. Integral 480-120/208V transformers, complete with secondary thermal magnetic circuit breakers, supply power to the integral or remote 120/208V lighting and power panels.

Each 120/208V lighting and power panel consists of a number of bolt-on thermal magnetic type circuit breakers which supply power to lighting, small motor loads, motor space heaters, equipment space heaters and similar miscellaneous loads. In general, all lighting is served from a single separate lighting panel. In general, power for all small motor loads, etc. is supplied from a single separate power panel. In addition, a separate power panel is used to supply power to lighting and building equipment loads for the Swgr/MCC Control Room Enclosure Building.

The 120V UPS (uninterruptible power supply) system equipment consists of a battery and a combination battery charger/invertor which supplies regulated AC power to the distributive

control system (DCS) equipment via its associated 120V power panel. The battery, through the inverter, has the capacity to maintain AC power to the power panel for 30 minutes after a failure of normal AC power to the battery charger/inverter. Normal AC power is supplied from an isolation type transformer in the motor control center. The power panel consists of a number of bolt-on thermal magnetic type circuit breakers which supply power to the various DCS components.

The 125V DC distributive panel consists of a number of bolt-on thermal magnetic circuit breakers which supply power to the control circuits of the 2.4-kV vacuum breakers in the switchgear.

Natural Gas System The natural gas supply for the WSA-SNOX Demonstration Facility will be provided by the East Ohio Gas Company from a Metering and Regulation (M&R) Station located adjacent to the Ohio Edison, Niles Station property. This M&R Station represents a new addition to the pre-existing East Ohio Gas Company main supply header. Specifically, the Natural Gas Supply Line will provide fuel to operate the 1st, 2nd, and 3rd Support Burners as well as heat the site laboratory and control houses.

Fuel gas piping from the M&R Station will be run underground to the Demonstration Facility with the primary balance of the piping to the specific equipment to be above ground. Fuel gas piping will vary in size from ½" to 2-½" diameter. The pipe materials will be carbon steel Sch. 40 and carbon steel Sch. 80. All gas piping will be treated to operate at 100 psi. During operation, gas metering for specific equipment, such as the Support Burners, will be accomplished through localized flow and pressure valves and valve train systems. The fuel gas usage of major pieces of equipment will be monitored via local flow totalizers.

Water System The SNOX Demonstration Facility will utilize and tap the existing Ohio Edison water systems for supply of cooling water, potable water, and fire protection water.

The Cooling Water System will consist of 2-½" diameter carbon steel Schedule 40 pipe rated for service at 90 psig. The cooling water will be specifically used for cooling of the product sulfuric acid.

The Potable Water System will consist of both 2" and 1" copper piping rated for service at 70 psig. This water system will be used for eye wash, showers, laboratory service, and sulfuric acid dilution.

The Fire Protection Water System will consist of 6" diameter fire protection piping used to service a new plant fire hydrant located in the SNOX Facility Process Area.

4.3 Summary of Major Equipment

Table 4-3 Major Equipment List

Heat Exchanger

E-204	Gas/Gas Exchanger
E-209	WSA Condenser
E-222	Acid Cooler

Burner

H-201	1st Support Burner
H-207	2nd Support Burner
H-210	3rd Support Burner

Filter

A-202	Bag Filter
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Reactor

R-206	SCR Reactor
R-208	SO ₂ Converter

Table 4-3 Major Equipment List (Cont'd)

Tank and Vessel

B-220	Acid Holding Tank
B-223 A/B	Acid Storage Tank
B-225 A/B	Ammonia Storage Vessel
B-270	Sulfuric Acid Dilution Water Tank

Pump

P-221 A/B	Acid Circulation Pump
P-224	Acid Pump
P-230	Ammonia Feed Pump
P-235	Sulfuric Acid Dilution Water Pump

Blower

K-203	Flue Gas Blower
K-230	Cooling Air Blower
K-241	Booster Fan

Miscellaneous

X-205	Ammonia/Flue Gas Mixing Unit
X-240	Ammonia/Air Mixing Unit
X-280	Catalyst Screening Unit

5.0 PROCESS CAPITAL COST

Cost data from design and installation of the SNOX Demonstration Plant is listed in Table 5-1. Process areas are broken down into: particulate collection, NO_x reduction, SO₂ oxidation, acid condensation, acid conditioning and storage, and balance of plant. Construction supervision and mechanical and electrical installation of equipment were summed and proportioned according to total equipment cost for each of the six areas (shown as one "Installation" entry). All equipment costs are for year 1991.

Total installed equipment cost for the demonstration plant was \$14,433,790. Engineering and all other management expenses for the project totaled \$5,677,214 for Phases I and II. This results in a total plant cost of \$20,011,004. G&A expenses are estimated to be 11%, and the cost including G&A expense is therefore \$22,223,214.

With respect to retrofit considerations, the fact that the SNOX unit was on a slipstream avoided major changes to existing boiler/ESP ductwork. However, the plant was located a considerable distance from the slipstream take off and tie in to the existing stack, so that costs for ductwork and support steel was significantly higher than an integral arrangement. Retrofit factors will be very site specific and will be related to the available space, and the ease with which the flue gas/heated air from SNOX can be routed from boiler to SNOX to stack/to boiler.

As with any process plant, size of the installation will have a major impact on cost per unit of treatment, such as dollars per kilowatt. Because the SNOX demonstration unit is relatively small in size (35 MW equivalent), the cost per kilowatt for larger units will be less than that calculated from the demonstration plant. This scale factor will be estimated and discussed in Volume 2 of the final report.

Table 5-1 Major Equipment Costs - 1991 Dollars

DESCRIPTION	VALUE	TOTAL	DESCRIPTION	VALUE	TOTAL
Particulate Collection			Balance of Plant		
Installation	521,708		Installation	2,378,285	
Ash Handling Equipment	106,211		Anchor Bolts	30,750	
Baghouse	771,146		Coating and Lining	143,994	
Filter Bags/Cages	98,064	1,497,129	Control Building	262,423	
NOx Reduction			Dampers	99,085	
Installation	304,497		Duct Tie-In (Phase 1)	65,697	
Ammonia Blower	12,670		Electrical Power	226,260	
Ammonia Nozzles	1,090		Expansion Joints	113,752	
Ammonia Tank	18,730		G/G Heat Exchanger	781,920	
SCR Reactor	110,017		Geotechnical	356,097	
Catalyst	429,000	876,004	Direct Heaters	71,848	
SO2 Oxidation			High Temperature Ducts	182,394	
Installation	421,881		ID & Cooling Air Fans/Motors	266,770	
Catalyst	429,000		Low Temperature Ductwork	388,378	
SO2 Converter	177,883		Mod 300 Control System	77,948	
SO2 Converter Support Steel	185,034	1,213,798	Pilings and Foundation (phase 1)	660,209	
Acid Condensation			Pilings and Foundation (phase 2)	293,350	
Installation	1,203,941		Sump Pump	15,270	
WSA Tower (SP-Milan)	2,200,000		Venturi	17,550	
Acid Brick Installation	59,959	3,463,900	Support Steel	409,795	6,841,775
Acid Conditioning & Storage					
Installation	188,116		TOTAL INSTALLED EQUIPMENT COST		14,433,790
Acid Pump	19,700		TOTAL ENGINEERING		5,677,214
Acid Loading Station	23,440		TOTAL INSTALLED COST		20,011,004
Acid Holding Tank	3,430				
Acid Cooler	35,430		G&A @ ESTIMATED 11%		2,212,210
Acid Tanks	50,054				
Piping	216,404		GRAND TOTAL (EQUIP. COST, ENG, G&A)		22,223,214
Pump, Holding Tank	4,610	541,184			

6.0 ESTIMATED OPERATING COST

Operating costs have been estimated for the demonstration plant along with an estimate of the projected startup costs. Operating costs are broken down into fixed and variable components.

6.1 Fixed and Variable Operating and Maintenance Cost

Table 6-1 contains the estimates of fixed and variable O&M costs for the demonstration plant. With respect to fixed costs, one operator per shift has been assumed to operate the system using the computerized Distributive Control System (DCS). Assistance from a roving operator is assumed to be provided from the utility plant personnel and the cost is included in the Support Labor cost. Due to the totally catalytic nature of the process and the minimal rotating equipment, a relative low Maintenance Labor and Material value has been assumed - \$116,800/yr for Labor and \$200,000/yr for Material. Total Administrative and Support Labor cost has been assumed at 30% of the Operating and Maintenance Labor, for a total of \$140,000/yr. Total Annual Fixed O&M cost is summed up to be \$806,240/yr.

Variable operating cost is shown in the same Table 6-1, and contains the elements of consumables and products generated. Electrical power consumption for the process is primarily comprised of the requirement for the flue gas fan and cooling air fan for the WSA condenser. Natural gas consumption is that required for the three support burners; although as has been described the demonstration plant uses two additional burners compared to a full-size, integrated installation. Natural gas consumption is therefore proportionally higher for the demonstration plant. Ammonia consumption is that required for the SCR unit. A cost of \$190/ton has been assumed which is converted to \$.095/lb in the table. The small amount of potable water consumed is that employed to dilute the acid if necessary to the commercially traded concentration of 93.2%. As indicated, the cost associated with this consumption is negligible. Cooling water is used to cool the acid exiting the condenser to near ambient temperature. Cooling water is valued at \$.15/kgal. Sulfuric acid produced by the process will be sold locally and the estimated value is \$30/ton, converted to \$.015/lb in the table.

Total Variable Operating cost is summed to be \$63.2/hr in Table 6-1. The total planned operating hours for the plant is estimated to be 11,240; which is based on a 22 month test program and an operating factor of 70%. Base year for both the fixed and variable operating costs is 1992.

6.2 Summary of Estimated Startup Costs

Table 6-2 contains the estimate of startup costs for the demonstration plant. A startup period of two months has been assumed, and an operating factor of 50% has been assumed to proportion the consumables (variable operating cost). Fixed operating costs have been proportioned based on calendar time from the values listed in Table 6-1, with a factor of 1.5 applied to account for the increased startup duties required. This includes functional check out of equipment, personnel training, calibrating and adjusting control systems, and allowance for startup inefficiencies and breakdowns. Total startup cost is projected to be \$236,025.

Table 6-1 Summary of Estimated Operating Costs - Base Year 1992

ANNUAL FIXED OPERATING COST			
Operating Cost Details			
	Number of Operators per Shift	1	
	Number of Shifts per Week	4.2	
	Operating Pay Rate per Hour (\$)	40	
			Cost, \$/yr
1. Total Annual Operating Labor Cost			349,440
2. Total Annual Maintenance Labor Cost			116,800
3. Total Annual Maintenance Material Cost			200,000
4. Total Annual Administrative and Support Labor Cost			140,000
5. TOTAL ANNUAL FIXED O&M COST			806,240

VARIABLE OPERATING COST				
Commodity	Unit	\$/Unit	Quantity/hr	Cost (\$/hr)
Electrical Power	kWh	0.02	875	17.5
Natural Gas	kSCF	3.00	23.7	71.1
Ammonia	lb	.095	168	16.0
Potable Water	kgal	.6	.008	Negligible
Cooling Water	kgal	.15	6.5	1.0
Sulfuric Acid (Credit)	lb	.015	2827	(42.4)
TOTAL VARIABLE OPERATING COST				63.2

TOTAL PLANNED OPERATING HOURS FOR DEMONSTRATION	11240
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Table 6-2 Summary of Estimated Startup Costs - Base Year 1992

Start-up Cost Element	Cost, \$
Operating Labor Cost	87,360
Maintenance and Materials Cost	79,200
Administrative and Support Cost	23,330
Commodity Cost	
1. Electrical Power	12,775
2. Natural Gas	51,900
3. Ammonia	11,680
4. Potable Water	Negligible
5. Cooling Water	730
6. Sulfuric Acid (Credit)	(30,950)
TOTAL STARTUP COSTS	236,025

Length of Startup Period, Months	2
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7.0 COMMERCIAL APPLICATIONS

The SNOX technology is applicable to all electric power plants and industrial/institutional boilers regardless which fuel is fired as long as NO_x and SO_x are to be removed - the process "sees" only the flue gas. The only limit is that a moderate amount of space is needed somewhat near the boiler so that the flue gas can be economically brought to the SNOX unit, processed and returned to the stack.

The following table (7-1) lists common site-specific factors with respect to power plants and the impact on the SNOX process.

Table 7-1 Impact of Site Specific Factors on the SNOX Technology

Coal type and characteristics	Two effects exist: 1) Large amounts of arsenic or other catalyst poisons in the coal may reduce catalyst life; 2) Process economics are better for high sulfur coal
Boiler size	No effect other than some diseconomies of scale for small units
Boiler age	No effect
Boiler heat release	No effect
Capacity factor limitation	No effect
Load profile applicability	Only economic effects; economics are better for a base load application
Boiler firing type	No effect
Boiler firing configuration	No effect
Boiler bottom type	No effect
Geographic applicability	No effect other than marketability of shipping/selling the sulfuric acid product

Table 7-1 Impact of Site Specific Factors**(Cont'd)**

Furnace dimensions	No effect
Reheat or non-reheat steam	No effect
Steam turbine characteristics	No effect
Particulate collector requirements	High efficiency particulate collection required. Higher loadings affect SO ₂ catalyst cleaning frequency and replacement interval, impacting operating cost.
Raw materials requirements	Only ammonia for the NO _x removal portion of the process
By-product marketing	Somewhat site specific although sulfuric acid output from SNOX plants will be very small compared to total U.S. production and consumption; will be able to under price "on purpose" production of acid

A full scale SNOX plant is also being designed and constructed on a parallel path with the U.S. demonstration plant. The plant is being retrofitted to a 300 MW coal fired boiler in Denmark with a flue gas flow of maximum 1,000,000 Nm³/hr. It is anticipated to start up in the fourth quarter of 1991. Coal sulfur contents are expected to be 1-3%.

APPENDIX A

<u>Drawing Number</u>	<u>Description</u>
18958-3E-0000	General Arrangements
18958-3E-0001	General Arrangements
18958-3E-0002	General Arrangements
18958-3E-0003	General Arrangements
18958-3E-0004	General Arrangements
18958-3E-0005	General Arrangements
18958-3E-0006	General Arrangements
18958-3E-0007	General Arrangements
18958-3E-0008	General Arrangements
18958-3E-0009	General Arrangements
18958-3E-0010	General Arrangements
18958-3E-2802	Process Flow Diagrams
18958-3E-2803	Process Flow Diagrams
18958-3E-2810	Piping
18958-3E-2819	Piping
18958-3E-2840	Piping
18958-3E-2841	Piping
18958-3E-3025	Duct Drawings
18958-3E-3026	Duct Drawings
18958-3E-3027	Duct Drawings
18958-3E-3028	Duct Drawings
18958-3E-3029	Duct Drawings
18958-3E-3030	Duct Drawings
18958-3E-3031	Duct Drawings
18958-3E-3032	Duct Drawings
18958-3E-3033	Duct Drawings
18958-3E-3034	Duct Drawings
18958-3E-3035	Duct Drawings
18958-3E-3036	Duct Drawings
18958-3E-3037	Duct Drawings
18958-3E-3038	Duct Drawings
18958-3E-3039	Duct Drawings
18958-3E-3040	Duct Drawings
18958-3E-3041	Duct Drawings
18958-3E-3042	Duct Drawings
18958-3E-3043	Duct Drawings
18958-3E-3044	Duct Drawings
18958-3E-3045	Duct Drawings
18958-3E-3046	Duct Drawings
18958-3E-3047	Duct Drawings
18958-3E-3048	Duct Drawings

<u>Drawing Number</u>	<u>Description</u>
18958-3E-3049	Duct Drawings
18958-3E-3050	Duct Drawings
18958-3E-3051	Duct Drawings
18958-3E-3052	Duct Drawings
18958-3E-3053	Duct Drawings
18958-3E-3054	Duct Drawings
18958-3E-3055	Duct Drawings
18958-3E-3056	Duct Drawings
18958-3E-3057	Duct Drawings
18958-3E-3058	Duct Drawings
18958-3E-3400	Acid Tanks
18958-3E-3401	Acid Tanks
18958-3E-3402	Acid Tanks
18958-3E-3403	Acid Tanks
18958-3E-4201	Motor Control Center
18958-3D-4300	Switchyard
18958-3D-4301	Transformers
18958-3D-4302	Transformers
18958-3D-4310	Switchgear
18958-3D-4311	Switchgear
18958-3D-4312	Control Wiring Diagrams
18958-3D-4313	Control Wiring Diagrams
18958-3D-4320	Control Wiring Diagrams
18958-3D-4321	Control Wiring Diagrams
18958-3D-4323	Control Wiring Diagrams
18958-3D-4324	Control Wiring Diagrams
18958-3D-4325	Control Wiring Diagrams
18958-3D-4327	Control Wiring Diagrams
18958-3D-4330	Control Wiring Diagrams
18958-3D-4331	Control Wiring Diagrams
18958-3D-4332	Control Wiring Diagrams
18958-3D-4334	Control Wiring Diagrams
18958-3D-4335	Control Wiring Diagrams
18958-3D-4336	Control Wiring Diagrams
18958-3D-4338	Control Wiring Diagrams
18958-3D-4339	Control Wiring Diagrams
18958-3D-4340	Control Wiring Diagrams
18958-3D-4341	Control Wiring Diagrams
18958-3D-4342	Control Wiring Diagrams
18958-3D-4343	Control Wiring Diagrams
18958-3D-4344	Control Wiring Diagrams
18958-3D-4345	Control Wiring Diagrams

<u>Drawing Number</u>	<u>Description</u>
18958-3D-4346	Control Wiring Diagrams
18958-3D-4347	Control Wiring Diagrams
18958-3D-4348	Control Wiring Diagrams
18958-3D-4349	Control Wiring Diagrams
18958-3D-4350	Control Wiring Diagrams
18958-3D-4351	Control Wiring Diagrams
18958-3D-4352	Control Wiring Diagrams
18958-3D-4353	Control Wiring Diagrams
18958-3D-4354	Control Wiring Diagrams
18958-3D-4355	Control Wiring Diagrams
18958-3D-4356	Control Wiring Diagrams
18958-3D-4357	Control Wiring Diagrams
18958-3D-4358	Control Wiring Diagrams
18958-3D-4359	Control Wiring Diagrams
18958-3D-4360	Control Wiring Diagrams
18958-3D-4361	Control Wiring Diagrams
18958-3D-4362	Control Wiring Diagrams
18958-3E-4601	Process & Instrumentation Diags
18958-3E-4602	Process & Instrumentation Diags
18958-3E-4603	Process & Instrumentation Diags
18958-3E-4604	Process & Instrumentation Diags
18958-3E-4605	Process & Instrumentation Diags
18958-3E-4606	Process & Instrumentation Diags
18958-3E-4607	Process & Instrumentation Diags
18958-3E-4608	Process & Instrumentation Diags
18958-3E-4609	Process & Instrumentation Diags
18958-3D-4629	Control Wiring Diagrams
18958-3D-4630	Control Wiring Diagrams
18958-3D-4631	Control Wiring Diagrams
18958-3D-4632	Control Wiring Diagrams
18958-3D-4633	Control Wiring Diagrams
18958-3D-4634	Control Wiring Diagrams
18958-3D-4635	Control Wiring Diagrams
18958-3D-4636	Control Wiring Diagrams
18958-3D-4637	Control Wiring Diagrams
18958-3D-4638	Control Wiring Diagrams
18958-3D-4639	Control Wiring Diagrams
18958-3D-4640	Control Wiring Diagrams
18958-3D-4641	Control Wiring Diagrams
18958-3D-4642	Control Wiring Diagrams
18958-3D-4643	Control Wiring Diagrams

<u>Drawing Number</u>	<u>Description</u>
18958-3D-4644	Control Wiring Diagrams
18958-3D-4645	Control Wiring Diagrams
18958-3D-4646	Control Wiring Diagrams
18958-3D-4647	Control Wiring Diagrams
18958-3D-4648	Control Wiring Diagrams
18958-3D-4649	Control Wiring Diagrams
18958-3D-4650	Control Wiring Diagrams
18958-3D-4651	Control Wiring Diagrams
18958-3D-4652	Control Wiring Diagrams
18958-3E-6400	Electrical Symbol List
18958-3E-6401	Cable Schedule
18958-3E-6402	Cable Schedule
18958-3E-6403	Cable Schedule
18958-3E-6404	Cable Schedule
18958-3E-6405	Cable Schedule
18958-3E-6406	Conduit Schedule
18958-3E-6407	Conduit Schedule
18958-3E-6408	Conduit Schedule
18958-3E-6409	Conduit Schedule
18958-3E-6410	Conduit Plan
18958-3E-6411	Conduit Plan
18958-3E-6412	Conduit Plan
18958-3E-6413	Conduit Plan
18958-3E-6415	Conduit Plan
18958-3E-6416	Conduit Plan
18958-3E-6417	Conduit Plan
18958-3E-6418	Conduit Plan
18958-3E-6419	Conduit Plan
18958-3E-6420	Conduit Plan
18958-3E-6426	Grounding Plan
18958-3E-6427	Grounding Plan
18958-3E-6428	Grounding Plan
18958-3E-6430	Panel Schedule
18958-3E-6431	Panel Schedule
18958-3E-6440	Conduit Schedule
18958-3E-6441	Conduit Schedule
18958-3E-6442	Conduit Schedule
18958-3E-6475	Conduit Plan
18958-3E-6477	Relay Panel
18958-3E-6490	Motor Control Center Arrg't.
18958-3E-6491	Motor Control Center Light Plan