EPA U.S. Environmental Protection Agency
Office of Research and Development

Industrial Environmental Research Laboratory
Research Triangle Park, North Carolina 27711

EPA-600/7-78-048
March 1978

SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS: ST. CLAIR STATION, DETROIT EDISON CO.

Interagency
Energy-Environment
Research and Development
Program Report

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into nine series. These nine broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and a maximum interface in related fields. The nine series are:

1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development
8. "Special" Reports
9. Miscellaneous Reports

This report has been assigned to the INTERAGENCY ENERGY-ENVIRONMENT RESEARCH AND DEVELOPMENT series. Reports in this series result from the effort funded under the 17-agency Federal Energy/Environment Research and Development Program. These studies relate to EPA's mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems. The goal of the Program is to assure the rapid development of domestic energy supplies in an environmentally-compatible manner by providing the necessary environmental data and control technology. Investigations include analyses of the transport of energy-related pollutants and their health and ecological effects; assessments of, and development of, control technologies for energy systems; and integrated assessments of a wide range of energy-related environmental issues.

EPA REVIEW NOTICE

EPA-600/7-78-048c
March 1978

SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS: ST. CLAIR STATION, DETROIT EDISON CO.

by

Bernard A. Laseke, Jr.

PEDCo Environmental, Inc.
11499 Chester Road
Cincinnati, Ohio 45246

Contract No. 68-01-4147
Task 3
Program Element No. EHE624

EPA Project Officer: Norman Kaplan

Industrial Environmental Research Laboratory
Office of Energy, Minerals and Industry
Research Triangle Park, N.C. 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, D.C. 20460

ACKNOWLEDGMENT

This report was prepared under the direction of Mr. Timothy W. Devitt and Dr. Gerald A. Isaacs. The principal author was Mr. Bernard A. Laseke.

Mr. Norman Kaplan, EPA Project Officer, had primary responsibility within EPA for this project report. Information on plant design and operation was provided by Mr. James E. Meyers, SO_2 Program Manager, Detroit Edison Co.; Mr. Thomas Morasky, Senior Project Engineer, Detroit Edison Co.; and Mr. Carlton A. Johnson, Project Manager, Peabody Engineered Systems.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

SUMMARY

A full-scale flue gas desulfurization demonstration system utilizing a calcium-based limestone slurry process for removal of sulfur dioxide from boiler flue gas was backfitted onto one-half of Unit 6 (325 MW) at the St. Clair Power Plant of the Detroit Edison Company. The system consists of two identical parallel scrubbing trains with a common recirculation tank, induced-draft fan, and oil-fired, hot-air-injection reheater. Each scrubbing train includes a Peabody-Lurgi radial-flow venturi scrubber for particulate removal followed by a high-velocity spray tower for sulfur dioxide removal.

The system was designed and installed by Peabody Engineered Systems in cooperation with the Detroit Edison Company. Development of the system resulted directly from a 1-MW pilot plant program conducted by Detroit Edison and Peabody from 1971 to 1973. Upon successful completion of this program, installation of the full-scale demonstration system began in February 1974. Construction was completed by December 1974. Shakedown and debugging operations conducted during 1975 included a cold gas run followed by four separate hot flue gas runs. The hot flue gas operations, which totalled more than 637 hours, revealed a number of problems, primarily mechanical. Following the necessary modifications, a 30-day system supplier qualification run and a week-long series of final acceptance tests were successfully completed by May 29, 1976.

On October 14, 1976, the utility initiated an in-house demonstration program in an effort to accumulate operating data and experience with the flue gas desulfurization equipment. The system operated continuously for 10 days, after which operation was interrupted for cleaning of a scrubber booster fan.

Operations were resumed on November 7 and continued without interruption during the remainder of the month. System availability* in the period was 80 percent. Reduction of system availability to 51 percent in December was caused by minor mechanical difficulties. On December 31, 1976, sulfur dioxide removal operations were completed. The scrubber system was shut down, and flue gas was bypassed around the system. The boiler remained in service and was operated in compliance with emission regulations by firing of low-sulfur (0.3 percent) western coal. During the following months the system was modified to operate in the particulate removal mode. Continuing to fire low-sulfur western coal, the utility resumed operation of the scrubber on October 13, 1977; the system removes primarily particulate matter and also some sulfur dioxide from the flue gas.

The design particulate and sulfur dioxide removal efficiencies for the scrubbing system are 99.7 and 90 percent, respectively. These values are based upon a design coal with the following characteristics: heat content, 26.3 MJ/kg (11,300 Btu/lb); ash content, 16 percent; sulfur and moisture contents, 4.0 and 5.9 percent, respectively.

The total direct cost of the scrubbing system, including installation, was reported to be $8,151,000 (1975). Indirect costs amounted to $4,937,000. Thus, the total installed capital costs are $13,088,000. On the basis of a net generating capacity of 163 MW, this cost is equivalent to approximately $80.5/kW.

Pertinent data on the facility and scrubbing system are summarized in Table 1.

---

*Availability: The number of hours the system is available, whether operated or not, divided by the number of hours in the period, expressed as a percentage.

Table 1. SUMMARY DATA, ST. CLAIR UNIT 6 FGD SYSTEM

Unit rating, MW (net)	325
Fuel	Pulverized coal
Average characteristics (design):	
Heating value, MJ/kg (Btu/lb)	26.3 (11,300)
Ash, percent	16.0
Sulfur, percent	4.0
Moisture, percent	5.9
FGD system rating, MW[a]	163
FGD system supplier	Peabody Engineered System
Process	Limestone
Type	Retrofit
Status	Terminated[b]
Start-up date	May 1976
FGD modules	Two
Removal efficiency, percent	
Particulate (design)	99.7
Sulfur dioxide (design)	90.0
Makeup water, l/min per MW	4.05
gal/min per MW	(1.07)
System capital cost, $/kW (net)	80.5

[a] Unit No. 6 is powered by a two-stage superheater incorporating two boiler furnaces. The north boiler is retrofitted with the scrubbing system.

[b] SO_2 removal operations were concluded on December 31, 1976. The scrubbing system resumed operations on October 13, 1977, removing primarily particulate and some SO_2 from low-sulfur western coal flue gas.

SECTION 1

INTRODUCTION

The Industrial Environmental Research Laboratory of the U.S. Environmental Protection Agency has initiated a study of the performance characteristics and reliability of flue gas desulfurization (FGD) systems operating on coal-fired utility boilers in the United States.

This report, one of a series dealing with such systems, describes a wet limestone scrubbing process developed by Peabody Engineered Systems, Inc., in cooperation with the Detroit Edison Company, and installed at the utility's St. Clair Power Plant. The report is based on information obtained during and after a plant inspection conducted for PEDCo Environmental on March 26, 1976, by Detroit Edison and Peabody personnel. The information is current as of December 1977.

Section 2 presents information and data on facility design and operation. Section 3 provides a detailed description of the FGD system. Section 4 analyzes the performance of the FGD system, the major operational problems, and the capital and annualized operating costs. Appendix A provides additional detailed design and operating data on the St. Clair Unit 6 facility.

SECTION 2

FACILITY DESCRIPTION

The St. Clair power plant of the Detroit Edison Company is located on the west bank of the St. Clair River in Belle River, Michigan, approximately 72 km (45 miles) northeast of downtown Detroit. The highly industrialized area includes another power-generating facility, the Lambton Generating Station, owned and operated by Ontario Hydro. A third power station now in the planning stages, Belle River, will consist of two coal-fired 676-MW power-generating units. The three stations will be located within 3.2 km (2 miles) of each other. Figure 1 shows the locations of the plants and their power-generating capacities.

The St. Clair power plant includes seven fossil-fuel-fired boilers, each coupled to its own turbine generator unit. The total combined net generating capacity is 1798 MW. The boilers for Units 1 through 5 were manufactured and installed by the Babcock and Wilcox Company. The boilers for Units 6 and 7 were manufactured and installed by Combustion Engineering, Inc., (C-E). Each boiler is served by a separate stack, the heights above grade ranging from 76 m (250 ft) to 183 m (600 ft).

Coal is fired in all seven boilers. In 1975, the coal for this facility came primarily from sources in Ohio and northern West Virginia. The average heating value was 27.2 MJ/kg (11,700 Btu/lb); ash and sulfur contents were approximately 15 and 3.5 percent, respectively. In addition, 17 to 20 percent of the coal supplied to the plant in 1975 came from the Decker, Montana, area. This low-sulfur western coal is now burned in all of the coal-fired units. Table 2 gives the average characteristics of the Montana coal.

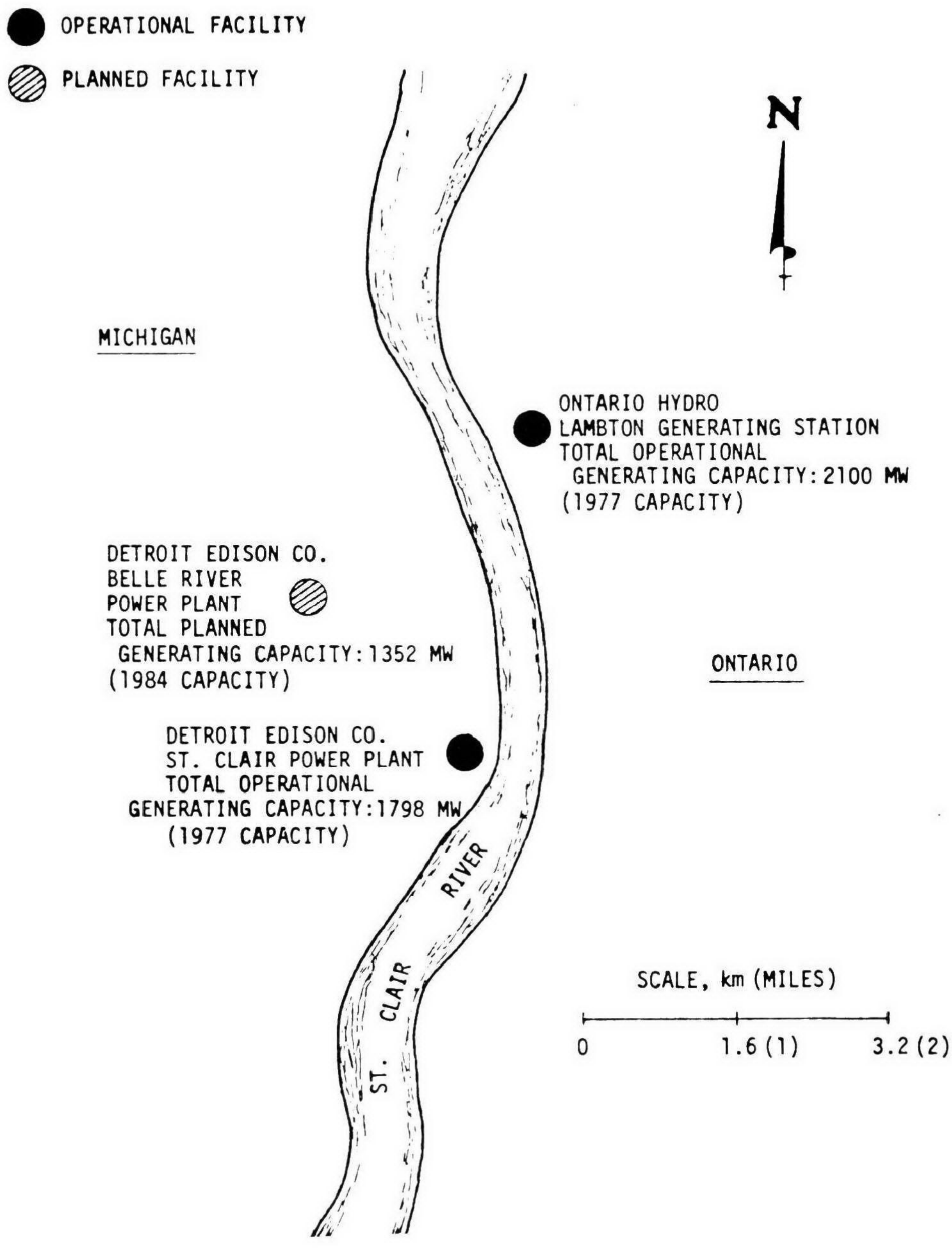

Figure 1. Operational and planned plants near Belle River, Michigan.

Table 2. CHARACTERISTICS OF LOW-SULFUR WESTERN COAL FIRED AT THE ST. CLAIR FACILITY

Fuel	Coal
Source	Decker, Montana Dietz Mine No. 1
Type	Subbituminous
Heat content, MJ/kg (Btu/lb)	22 (9600)
Volatile matter, wt. percent	33.7
Fixed carbon, wt. percent	39.5
Moisture, wt. percent	22.6
Ash, wt. percent	4.2
Sulfur, wt. percent	0.35
Grindability, Hardgrove index	50
Ash fusion temperature, spherical softening, °C (°F)	1188 (2170)
Quantity, 1000 Mg (tons)/year	776 (885)

Unit 6 is a peak-load unit with a net power-generation capacity of 325 MW. Steam is supplied to the generator from a coal-fired, two-stage steam superheater, containing two separate furnaces (the north and the south boilers). This unit was manufactured by C-E and placed in service in April 1961. Particulate controls installed on each furnace consist of mechanical collectors and an electrostatic precipitator (ESP).

The north boiler has been backfitted with a wet limestone scrubbing system for primary control of sulfur dioxide and secondary removal of particulates. The FGD system can handle 100 percent of the flue gas from the north boiler, rated at 163 MW (net). This capacity is equivalent to approximately 233 m^3/sec (493,500 acfm) at 132°C (270°F).

Table 3 summarizes information concerning plant and FGD system design, operation, and emissions.

The maximum allowable particulate and sulfur dioxide emissions for this unit, as covered by Michigan State Code R336.49, are 86 ng/J (0.2 lb/million Btu heat input) for particulate matter and 1.0 percent maximum sulfur content in fuel for sulfur dioxide. This sulfur dioxide emission regulation value took effect on January 1, 1978. The previous value, which covered the 1976 and 1977 operating period, was 1.5 percent maximum sulfur content in the fuel.

Table 3. DESIGN, OPERATION, AND EMISSIONS

ST. CLAIR UNIT 6

Unit	No. 6
Total rated generating capacity, MW	325
Boiler manufacturer	C-E
Year placed in service	1961
Unit heat rate, KJ/net kWh (Btu/net kWh)	9865 (9350)
Maximum coal consumption, Mg/hr (Short tons/hr)	60.1 (66.3)
Maximum heat input, 10^6 kg/hr (10^6 Btu/hr)	26.4 (1500)
Stack height above grade, m (ft)	130 (425)
Design maximum flue gas rate,	
m^3/sec @132°C	233
acfm @ 270°F	493,500
scfm @ 70°F	358,500
Emission controls:	
Particulate	Mechanical collectors, ESP, and venturi scrubber
Sulfur dioxide	Venturi scrubber and spray tower absorber
Particulate emission rates:	
Allowable, ng/J (lb/10^6 Btu)	86 (0.20)
Design[a], ng/J (lb/10^6 Btu)	13 (0.03)
Sulfur dioxide emission rates:	
Allowable, maximum sulfur percent in fuel	1.0
Design[a], ng/J (lb/10^6 Btu)	300 (0.7)

[a] Design values are based upon the outlet loadings achieved with the emission control system in service.

SECTION 3

FLUE GAS DESULFURIZATION SYSTEM

BACKGROUND INFORMATION

In 1971 the Detroit Edison Company initiated a program to evaluate the applicability of limestone slurry scrubbing. In cooperation with Peabody Engineered Systems, the utility designed and installed a 1-MW pilot plant at the River Rouge Station. The pilot plant originally included a Peabody-Lurgi venturi scrubber and a countercurrent tray tower absorber, along with recycle tanks and four recirculation pumps. Initial operation of the pilot unit on boiler flue gas revealed a number of major problems, the more serious ones including formation of sulfite and sulfate scale on the tower trays and mist eliminator; substantial increase in the slurry solids content, causing accelerated wear and erosion of slurry-handling equipment; and plugging of the radial-vane mist eliminator. Eventually it became necessary to operate at 100 percent blowdown with no water recirculation.

The severity of these problems prompted the utility and system supplier to cease operations and reevaluate the system design. Throughout 1972, the pilot plant was drastically modified to prevent the scaling and plugging. The major modifications included replacement of the countercurrent tray tower with a high-velocity countercurrent spray tower, inclusion of larger recycle tanks and pumps, an automatic pH control system, a slurry density control system, and a clear-water wash tray in the absorber ahead of the mist eliminator. Following completion of these modifications, the pilot plant was restarted in February 1973 and was operated continuously for about 500 hours without scaling or plugging. After additional successful test runs, the utility authorized installation of a full-scale demonstration unit at the St. Clair power plant.

PROCESS DESCRIPTION

The demonstration FGD system was installed on the coal-fired boiler of Unit 6. This boiler is a two-stage superheater unit, consisting of two separate furnaces designated as the north and south boilers. The demonstration FGD unit, installed on the north boiler, was sized to handle half of the total flue gas flow from Unit 6.

The scrubbing system consists of two identical parallel scrubbing trains with a common recirculation tank, an induced-draft fan, and an oil-fired, hot-air-injection reheating unit. Each train contains a Peabody-Lurgi radial-flow venturi scrubber followed by a high-velocity spray tower absorber. The scrubber incorporates a variable-throat design with a plug-type throat control regulated by a "wagon wheel" at the bottom of the scrubber. Each scrubbing train includes a clear-water wash tray located in the spray tower between the slurry spray section and the radial-vane mist eliminator.

Before entering the scrubbing system, the flue gas passes through mechanical collectors and an electrostatic precipitator (Wheelabrator-Frye) for primary particulate removal. The hot flue gas 132°C (270°F) then enters the scrubbing trains through conical wetted-wall quench sections contained in the venturi scrubbers. The gas is wetted with slurry from the recirculation tank by cocurrent and crosscurrent sprays. The quenched gas and slurry mixture then passes radially through the adjustable throat section of the venturi scrubber which consists of two opposing replaceable rings. The lower ring is contained in a fixed cup and is adjusted by the wagon wheel to maintain a designated pressure drop. Both the quench section and throat are constructed of 316L stainless steel. The remainder of the scrubber is constructed of rubber-lined carbon steel. Following passage through the throat, the gas continues through two 90-degree turns (situated at the venturi outlet and the absorber inlet in each scrubbing train), allowing maximum de-entrainment of particulate and collection in the sump area of the scrubber.

The gas then passes upward through the high-velocity spray tower, contacting the slurry countercurrently. The slurry is fed from the recirculation tank and sprayed into the gas stream by three pairs of spray banks. Each pair is equipped with a rubber-lined recirculation pump and piping network. The spray units incorporate large hollow-cone silicon carbide nozzles, which are resistant to plugging and abrasion.

Located between the slurry spray zone and the radial-vane mist eliminator is an impingement-type, clear-water wash tray, which is constantly supplied with fresh makeup water. This tray provides an interface between the slurry spray zone and the mist eliminator, minimizing the potential for scale, corrosion, and erosion of the mist eliminator.

The cleaned gas is fed into a duct common to both scrubber trains and leading to a wet, induced-draft booster fan. Following passage through the fan, the gas is reheated. The combustion chamber of the oil-fired reheater is located outside the gas duct. The unit burns No. 6 fuel oil to heat ambient air, which is then injected into the gas stream through a diffuser. The reheat system is designed to raise the temperature of the flue gas stream from 52°C (125°F) to 135°C (275°F).

The flue gas cleaning wastes are discharged from both the venturi scrubber and spray tower absorber into a single recycle tank that serves both scrubbing trains. This tank, equipped with four separate agitators, allows completion of the chemical absorption reactions, addition of fresh alkali, discharge of spent alkali, and recirculation of the scrubbing solution to the scrubber and absorber towers.

The spent scrubbing slurry and collected fly ash solution are discharged from the recycle tank through an overflow nozzle into a collection sump and then are pumped to a clay-lined settling pond. The pond water is recycled for use in limestone preparation and in maintaining the water balance in the scrubber recirculation tank.

A simplified process flow diagram of the St. Clair FGD system is presented in Figure 2. A cross-sectional view of the scrubber-absorber train is provided in Figure 3.

DESIGN PARAMETERS

Fuel

The FGD system was designed to process flue gas resulting from combustion of coal in the Unit 6 north boiler, which has a net rating of 163 MW. Fuel characteristics of the coal on which the design was based are given in Table 4.

Table 4. DESIGN COAL ANALYSIS

(Weight percent)

Carbon	64.10
Hydrogen	4.12
Nitrogen	1.07
Sulfur	4.00
Oxygen	4.00
Ash	16.00
Moisture	5.90

FGD System

Table 5 summarizes the design parameters of the St. Clair FGD system. The values are based on the design coal characteristics given in Table 3 and on upstream particulate control by mechanical collectors and an ESP.

Particulate Removal

Primary particulate removal is in the Peabody-Lurgi radial-flow venturi scrubbers. Design parameters are summarized in Table 6.

Sulfur Dioxide Removal

Although the venturi scrubber removes an estimated 35 to 50

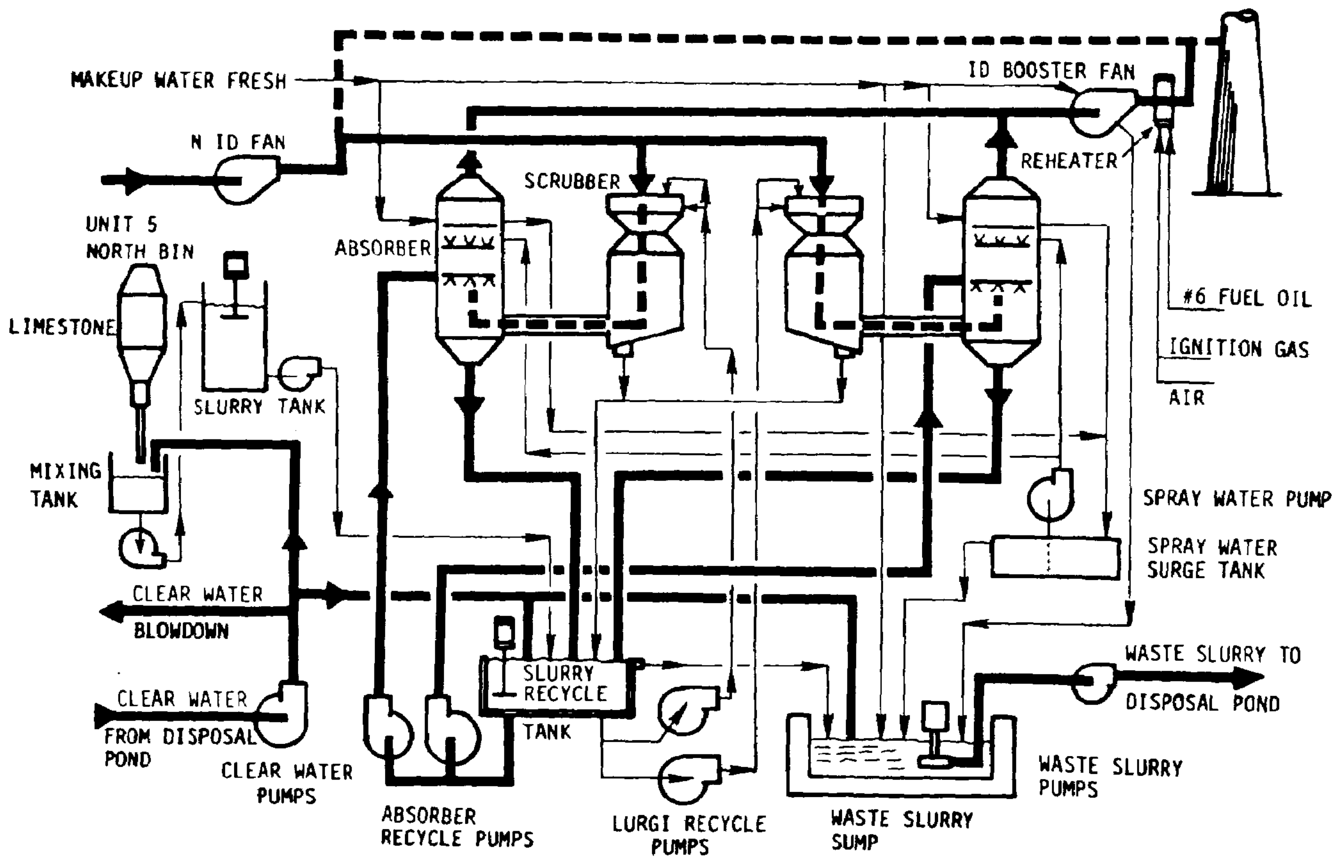

Figure 2. Simplified process flow diagram, St. Clair FGD system.

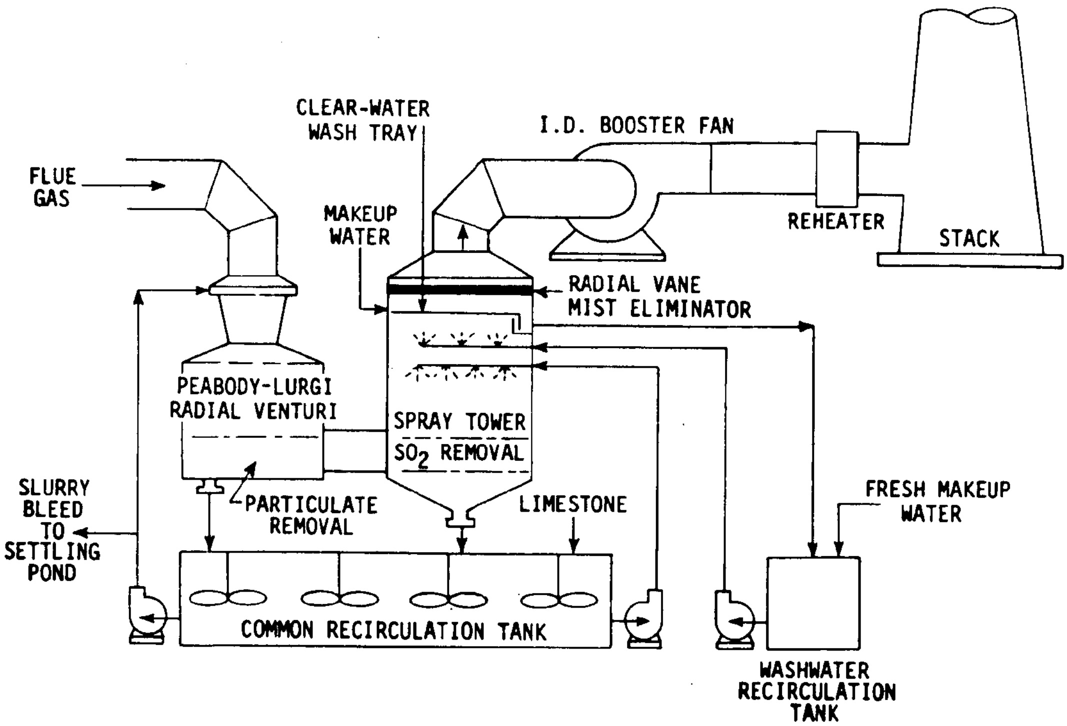

Figure 3. Simplified cross-sectional view of the scrubber-absorber, St. Clair FGD system.

Table 5. DESIGN PARAMETERS, ST. CLAIR FGD SYSTEM

Flue gas inlet:	
Temperature, °C (°F)	132 (270)
Volume, m^3/sec (acfm)	233 (493,500)
Particulate, g/sec (lb/hr)	2274 (18,804)
mg/dm^3 (gr/dscf)	8.2 (3.6)
Sulfur dioxide, g/sec (lb/hr)	1336 (10,600)
ppm	3000
Flue gas outlet:	
Temperature, °C (°F)	48 (118)
Volume, m^3/sec (acfm)	203 (403,000)
Particulate, g/sec (lb/hr)	6 (48)
mg/dm^3 (gr/dscf)	0.23 (0.1)
Sulfur dioxide, g/sec (lb/hr)	134 (1,060)
ppm	300
Particulate removal efficiency, percent	99.7
Sulfur dioxide removal efficiency, percent	90

Table 6. DESIGN PARAMETERS, PEABODY-LURGI VENTURI SCRUBBER

Materials of construction:	
Quench section	316L SS
Throat	316L SS
Internals	Rubber-lined carbon steel
Shell	316L SS
Flue gas volume, m^3/sec (acfm)	116 (246,750)
Flue gas temperature, °C (°F)	132 (270)
Flue gas velocity, m/sec (ft/sec)	28 (93)
Pressure drop, kPa (in. H_2O)	3.5 (14)
Liquid recirculation rate l/sec (gal./min)	279 (4420)
Maximum continuous liquid-to-gas ratio (L/G) l/m^3 (gal./1000 acf)	2.4 (20)

percent of the sulfur dioxide from the flue gas, primary sulfur dioxide removal is in the spray tower. Table 7 summarizes the design parameters of the countercurrent spray-tower absorber unit.

Limestone Preparation and Solution Recirculation

Tables 8 and 9 summarize the design features of the limestone preparation facilities and the scrubbing solution recirculation system.

Sludge Disposal

The scrubbing wastes created by chemical absorption of sulfur dioxide from the flue gas are discharged from the system through the recirculation tank. The waste solution overflows into a collection sump and is discharged to a clay-lined, on-site disposal pond. Table 10 presents design features of the sludge disposal facility.

PROCESS CHEMISTRY: PRINCIPAL REACTIONS

The chemical reactions involved in the St. Clair wet limestone scrubbing process are highly complex. Although details are beyond the scope of this discussion, the principal chemical mechanisms are described below.

The first and most important step in the wet-phase absorption of sulfur dioxide from the flue gas stream is diffusion from the gas to the liquid phase. Sulfur dioxide is an acidic anhydride that reacts readily to form an acidic species in the presence of water.

$$SO_2 \uparrow \rightleftharpoons SO_{2(aq.)}$$

$$SO_{2(aq.)} + H_2O \rightleftharpoons H_2SO_3$$

In addition, some sulfur trioxide is formed from further oxidation of the sulfur dioxide in the flue gas stream.

$$2SO_2 \uparrow + O_2 \uparrow \rightleftharpoons 2SO_3 \uparrow$$

Because conditions are thermodynamically but not kinetically favorable, only small amounts of sulfur trioxide are formed.

Table 7. DESIGN PARAMETERS, HIGH-VELOCITY SPRAY TOWER

Materials of construction:	
Spray bank nozzles	Silicon carbide
Clear-water wash tray	316L SS
Radial-vane mist eliminator	316L SS
Absorber shell	316L SS
Flue gas volume, m^3/sec (acfm)	101 (215,000)
Flue gas temperature, °C (°F)	48 (118)
Flue gas velocity, m/sec (ft/sec)	2.9 (9.5)
Pressure drop, kPa (in. H_2O)	2.5 (10)
Maximum recirculation rate, l/sec (gal./min)	1117 (17,700)
Maximum L/G, l/m^3 (gal./1000 acf)	11 (80)

Table 8. LIMESTONE PREPARATION AND STORAGE FACILITIES

Preparation equipment	None - the limestone is received, prepared, ground to 90% minus 200 mesh
Storage capacity, Mg (ton)	680 (750)
Limestone feed rate, Mg/hr (ton/hr)	10 (11)
Stoichiometric addition, percent	130
Limestone slurry storage, l (gal.)	567,817 (150,000)
Limestone slurry, percent solids	35.0
Slurry feed pumps	2
Flow rate/pump, l/sec (gal./min)	14 (215)
Point of addition	Recirculation tank

Table 9. DESIGN PARAMETERS, SLURRY RECIRCULATION SYSTEM

Recirculation tank	1
Dimensions:	
Diameter, m (ft)	15 (48)
Height, m (ft)	12 (38)
Materials of construction:	
Shell	Carbon steel
Lining	Ceilcote
Retention time, minutes	10
Recirculation pumps:	9
Venturi scrubber	3
Capacity, l/sec (gal./min)	279 (4420)
Service	2 operational/1 spare
Spray tower absorber	6
Capacity, l/sec (gal./min)	372 (5900)
Service	5 operational/1 spare

Table 10. DESIGN FEATURES, ST. CLAIR SLUDGE DISPOSAL SYSTEM

Disposal pond	1
Type	Diked, clay-lined
Distance from FGD system, m (ft)	488 (1600)
Transportation method	Pipeline
Dimensions:	
Area, m^2 (acres)	43706 (10.8)
Depth, m (ft)	3 (10)
Capacity, Mg (tons)	96,606 (106,490)
Lifetime, years	1
Maximum discharge rate, kg/sec (ton/hr) (dry)	318 (21)
Water content, percent	92
Chemical composition of sludge:	
Calcium carbonate, percent	15.3
Calcium sulfite hemihydrate, percent	21.7
Calcium sulfate dihydrate, percent	58.9
Fly ash	4.1
Pond water return points	Limestone slurry preparation, slurry recycle tank
Pond water purge rate, l/sec (gal./min)	11 (175)

This species, like sulfur dioxide, is an acidic anhydride that reacts readily to form an acid in the presence of water.

$$SO_3 \uparrow \rightleftharpoons SO_{3(aq.)}$$

$$SO_{3(aq.)} + H_2O \rightleftharpoons H_2SO_4$$

The sulfurous and sulfuric acid compounds are polyprotic species; the sulfurous species is weak and the sulfuric species, strong. Their dissociation into ionic species occurs as follows:

$$H_2SO_3 \rightleftharpoons H^+ + HSO_3^-$$

$$HSO_3^- \rightleftharpoons H^+ + SO_3^=$$

$$H_2SO_4 \rightleftharpoons H^+ + HSO_4^-$$

$$HSO_4^- \rightleftharpoons H^+ + SO_4^=$$

Analogous to the oxidation of sulfur dioxide to form sulfur trioxide, oxidation of sulfite ion by dissolved oxygen (DO) in the scrubbing slurry is limited.

$$2SO_3^= + O_{2(aq.)} \rightleftharpoons 2SO_4^=$$

This reaction occurs in the aqueous phase like the gas-phase oxidation of sulfur dioxide; conditions are favorable thermodynamically and unfavorable kinetically. Formation of sulfate is a second-order reaction that is directly proportional to the concentrations of DO and sulfite ion. Since the DO content of the scrubbing solution should be relatively constant because of the excess oxygen in the flue gas, the formation of sulfate ion in the aqueous phase depends primarily on sulfite ion concentration. Since sulfite solubility increases as pH decreases, sulfate ion production occurs more readily in the acidic pH range.

The limestone absorbent, which is approximately 85 to 95 percent calcium carbonate by weight, enters the scrubbing system as a slurry with water. It is insoluble in water, and solubility increases only slightly as the temperature increases. When introduced into the scrubbing system, the slurry dissolves and ionizes into an acidic aqueous medium, yielding the ionic products of calcium, carbonate, bicarbonate, and hydrogen.

$$CaCO_3 \downarrow \rightleftharpoons CaCO_{3(aq.)}$$

$$CaCO_{3(aq.)} \rightleftharpoons Ca^{++} + CO_3^{=}$$

$$Ca^{++} + H^{+} + CO_3^{=} \rightleftharpoons CaHCO_3^{+}$$

$$CaHCO_3^{+} \rightleftharpoons Ca^{++} + HCO_3^{-}$$

The chemical absorption of sulfur dioxide occurs in the venturi scrubber and spray tower and is completed in the external recirculation tank. The reaction products precipitate as calcium salts and the scrubbing solution is recycled. Following are the principal reaction mechanisms for product formation and precipitation.

$$Ca^{++} + SO_3^{=} \rightleftharpoons CaSO_3$$

$$CaSO_3 + 1/2H_2O \rightleftharpoons CaSO_3 \cdot 1/2H_2O$$

$$Ca^{++} + SO_4^{=} \rightleftharpoons CaSO_4$$

$$CaSO_4 + 2H_2O \rightleftharpoons CaSO_4 \cdot 2H_2O$$

The hydrated calcium sulfite and calcium sulfate reaction products, along with the collected fly ash and unreacted limestone, are transferred to the disposal pond. The supernatant is recycled to the system.

PROCESS CONTROL

The process control system for the St. Clair FGD facility was designed by Peabody and Detroit Edison to maintain optimum scrubber operations with 0.5 man. Following are the principal design features.

- All key process variables are monitored and controlled automatically.

- The absence of check valves in the primary recirculation lines eliminates the possibility of their erosion and failure because of abrasive slurry service. System modulation is achieved by stepwise operation of recirculation pumps.

- The inlet scrubber ductwork contains no gas flow dampers. The design of the ductwork permits proper gas flow distribution at 0, 40, and 100 percent boiler loads.

- The flow of flue gas to the scrubbing trains is maintained externally by regulation of the boiler draft and combustion control system.

- Continuous flow loops are tapped, when needed, to control key process variables.

- The variables that are amenable to monitoring and control are pH and solids content of the scrubbing solution.

Following is detailed information concerning the regulation of pH and solids content.

pH Control

The addition of fresh limestone slurry to the system is regulated by monitoring the pH of the scrubbing solution in the common recirculation tank. The control for pH regulation is maintained in the slightly acidic range, 5.8 to 6.0. This range optimizes system performance as a function of sulfur dioxide removal, limestone utilization, and mechanical reliability.

Fresh makeup limestone slurry is pumped continuously through a piping loop connected to the slurry preparation tank. This loop is tapped by a flow control valve (gate valve), which is connected to a pH sensor, a Cambridge-supplied dip-type unit located in the common recirculation tank. When an excursion of the pH control range occurs, the sensor signals the flow control valve, which regulates the flow of slurry into the tank to compensate for the direction of the excursion (i.e., when pH drops below 5.8, flow of slurry is increased; when pH exceeds 6.0, flow is decreased). The effects of extended pH excursions on system operations are summarized as follows:

1. Low pH causes rapid formation of hard gypsum scale on the scrubber internals. This results from the cumulative effect of increasing calcium sulfite solubility and decreasing calcium sulfate solubility as the pH level decreases. Even when pH control is reestablished, the hard gypsum scale remains, requiring shutdown and cleanout before optimum operation can be resumed.

2. High pH causes poor limestone utilization and rapid plugging and fouling of the scrubber internals. Plugging, also called soft scale, is defined as the deposition of soft solids. As with hard scale, soft scale forms rapidly during the pH excursion. The chemical basis of soft scale formation is calcium sulfite solubility, which decreases rapidly as the pH increases and enters the alkaline range. The sulfite formations deposited on the scrubber internals are large, leaf-like masses, which are very soft. At high pH conditions, these soft solids provide deposition sites for excess calcium carbonate and fly ash in the scrubbing solution. Accumulations of calcium sulfite, calcium carbonate, inert silicon, and fly ash cause fouling of various scrubber internals. Unlike hard scale, soft scale is easily altered mechanically and thus maintenance of equipment requires less effort during shutdowns for cleanout. Also, when the pH of the solution is restored to the slightly acidic level, the soft scale film disappears because of the high solubility of calcium sulfite and calcium carbonate in lower pH environments.

Solids Content Control

The addition of supernatant to the system is regulated by monitoring the solids content of the scrubbing solution in the recirculation tank. The control level for the suspended solids concentration is maintained at a maximum of 15 percent by weight. When this level is exceeded, the system automatically compensates by discharging the spent slurry and bringing in pond supernatant.

The disposal pond supernatant is pumped continuously through a piping loop. This loop is tapped by a flow control valve (gate valve), which is connected to an Ohmart nuclear density meter in the common recirculation tank. When the sensor indicates that the control level has been exceeded, the meter signals the flow control valve and supernant is supplied directly to the recirculation tank. The quantity of supernatant added to the system is the amount needed to bring the suspended solids content below 15 percent. This results in a temporary water imbalance, which is automatically compensated for by gravity overflow into the waste slurry sump and pumping to the disposal pond. The continuous liquid flow between the sump and the disposal pond ensures a constant velocity of flow through the pipe under all load conditions. This minimizes the possibility that solids will settle out in the pipe, causing flow restrictions that could necessitate shutdown for cleanout.

Prolonged high solids content in the scrubbing solution leads to excessive wear and premature failure of slurry handling equipment, problems with system chemistry, and reduction of sulfur dioxide removal efficiency. Figure 4 presents a simplified diagram of the St. Clair process control network.

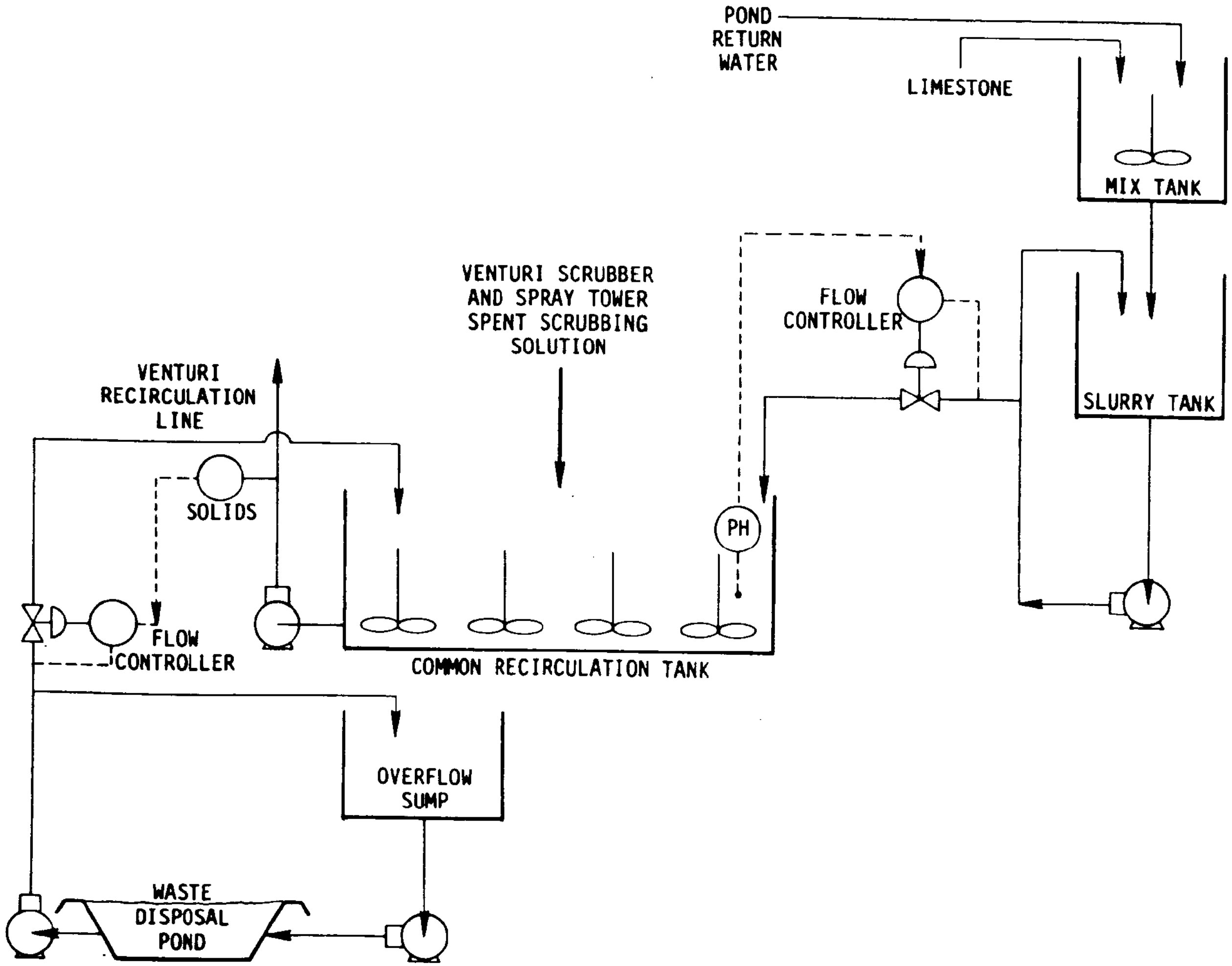

Figure 4. Simplified diagram of the process control network, St. Clair FGD system.

SECTION 4

FGD SYSTEM PERFORMANCE

BACKGROUND INFORMATION

The St. Clair FGD system is an experimental unit designed to provide engineering and operating data for future full-scale installations. Currently, however, the utility does not need full-scale FGD systems for the St. Clair coal-fired units, nor is such a need imminent. The utility has a long-term agreement with the Decker Coal Company for the supply of low-sulfur subbituminous coal from the Dietz mine in southern Montana. They are now burning this low-sulfur coal (0.3 to 0.4 percent sulfur) in all of the St. Clair coal-fired units and can comply with emission regulations without sulfur dioxide removal equipment.

The St. Clair experimental sulfur dioxide scrubbing program can be summarized as follows:

- Completion of all equipment installation, mechanical debugging, and prestart-up testing.
- Completion of system supplier qualification and acceptance tests.
- Completion of a demonstration program conducted by the St. Clair plant personnel.
- Termination of the sulfur dioxide removal operations. Continuation of operation in the particulate removal mode.

OPERATING HISTORY AND PERFORMANCE

Peabody Engineering and Detroit Edison undertook the development of limestone scrubbing technology with a 1-MW pilot plant at the River Rouge Station in Detroit, Michigan. Intermittent operation from 1971 to 1973 led to a large-scale system modification program, which included abandoning the tray-tower system design. Modified pilot plant operations began in February 1973 and continued through the year. Successful periods of continuous operation, lasting up to 21 days, ultimately resulted in authorization in February 1974 of a full-scale installation at the St. Clair plant.

Construction was virtually complete by December 1974. Mechanical checkout of auxiliary equipment, including pumps and the induced-draft fan, was complete by early 1975. A cold run with gas and water was successfully conducted on March 22 and 23, 1975. During this run, several minor system modifications were completed and preparations were made for test runs with hot flue gas. Four runs with hot flue gas and limestone slurry were conducted in June, August, October, and December 1975; these operations lasted 22 hours, 27 hours, 41 hours, and 547 hours, respectively. As the duration of successful operations increased with each run, the utility initiated and completed a 30-day qualification run and a week-long series of final acceptance tests by May 29, 1976. System operations in the qualification run were conducted exclusively by plant personnel. The system operability index* for the qualification run was 100 percent. Results of the 6-day final acceptance run indicated that sulfur dioxide removal efficiency was 90.9 percent with low-sulfur coal, exceeding the design guarantee for use with high-sulfur coal.

The in-house scrubber demonstration program was initiated on October 14, 1976. The system remained in continuous service for 10 days before operation was interrupted by fan balancing problems caused by excessive solids carry-over from the mist eliminator and wash water tray. Sulfur dioxide scrubbing resumed on November 7 and continued into December. Outages during

---

* Operability index: The number of hours the scrubbing system operated divided by the number of hours the boiler operated, expressed as a percentage.

the operating period are attributed primarily to mechanical problems. System availability values for November and December 1976 were 80 and 51 percent, respectively. The sulfur dioxide scrubbing program was completed on December 31, 1976.

Upon completion of the sulfur dioxide removal program, the scrubber system was removed from the flue gas path and Unit 6 remained in service firing low-sulfur western coal. The scrubber plant was shut down from January 1, 1977, through October 12, 1977. During this period the system was inspected and a number of design modifications were made. Scrubbing operations resumed on October 13, 1977, for removal of particulate only. In this mode of operation, the venturi scrubbers and spray tower absorbers remain in the flue gas stream. Scrubbing solution is circulated through the venturi scrubber and clear water is circulated through the wash water tray. No solution is circulated through the spray zone of the absorber towers. The scrubbers remove the fly ash not collected by the upstream mechanical collectors and electrostatic precipitator. They also remove some sulfur dioxide (approximately 35 to 50 percent) because of the alkalinity of the fly ash and the use of limestone in the scrubbing solution to prevent low pH swings and subsequent acid corrosion of the scrubber internals.

Table 11 summarizes Detroit Edison's development of scrubbing technology from initial operation of the River Rouge pilot plant to the present.

OPERATING PROBLEMS AND SOLUTIONS

The problems with scrubber operations to date are summarized in the comments section of Table 11. Most of the problems encountered during the system's relatively short operation have been mechanical and design-related. Although some problems relate to system chemistry, these are attributed to mechanical and design inadequacies. For example, development of scale in the induced-draft booster fan assembly resulted from carry-over

Table 11. SUMMARY OF ST. CLAIR FGD TECHNOLOGY DEVELOPMENT PROGRAM, DETROIT EDISON CO.

Period	Operations	Comments
1971 1972	River Rouge Pilot Plant	1-MW pilot plant development program was initiated by Detroit Edison and Peabody. Widespread scaling and plugging problems resulted in intermittent operations and ultimately led to shutdown for major modifications.
Aug. 72		Contract awarded to Peabody for the development of a full-scale demonstration system.
Feb. 73	Modified River Rouge Pilot Plant	The tray-type absorber was replaced by a countercurrent high-velocity spray tower. Restart occurred in February 1973 and continued on a controlled intermittent basis throughout the year. Maximum continuous operation period of 21 days was logged.
Feb. 74	St. Clair Demonstration Unit	The utility authorized scale-up of the pilot unit for installation at the St. Clair Power Plant, Unit 6, one-half of the total flue gas capacity.
Dec. 74 Jan. 75 Feb. 75		Installation of the St. Clair unit was virtually completed. A faulty instrument panel was returned to the manufacturer. Water and air testing of all auxiliary equipment (pumps, fan) was completed.
Mar. 75 Apr. 75 May 75	St. Clair air/water run	An air/water run was successfully conducted on March 22 and March 23. During this period all rubber-lined recycle pumps were repaired, and the limestone preparation and feed system were calibrated.
June 75	St. Clair hot flue gas run	The first hot flue gas run was conducted on June 22 for 22 hours. During this run the scrubber was purposely tripped off at loads of 40 to 80 percent to observe any possible detrimental effects on steam generation operations. None were detected. Following this run the following components were repaired: Lurgi throat, pH control system, target flow meters, and pump seal water flow indicators.
Aug. 75	St. Clair hot flue gas run	A second hot flue gas run begun on August 6 lasted 27 hours. Termination of system operations resulted from a reheater thermocouple failure. Inspection of the unit internally and analysis of operating data revealed no drastic abnormalities or malfunctions. Operating problems included: high solids content in the wash tray recycle tank, indicating excessive solids carryover through the mist eliminator and wash tray; plugging of the fresh water inlet boxes to the wash trays with solids; scale and slurry solids on demisters and wash trays; plugging of the wash tray underspray nozzles with sludge and slurry; failure of the pH controller; unequal distribution of gas flow between the two trains; duct vibrations; and SO_2 analyzer failures.

(continued)

Table 11 (continued).

Period	Operations	Comments
Sept. 75 Oct. 75 Nov. 75	St. Clair hot flue gas run	A third hot flue gas run of 41 hours was completed on October 9. The primary objective was to evaluate the effects on solids carry-over of increased fresh water wash and increased underspray to the wash system. The test run was terminated prematurely because loss of a boiler feed pump resulted in a reduced boiler load, causing subsequent weeping of the wash tray because of reduced flue gas velocity. Solids carry-over was significantly reduced. Process changes were implemented to provide sufficient wash water and tray underspray while preventing carry-over in a closed-water-loop mode.
Dec. 75	St. Clair hot flue gas run	Detroit Edison completed a fourth hot flue gas run from December 5 to December 29. Two interruptions occurred because of boiler shutdown for maintenance and interruption of the fuel oil supply to the reheater. A total of 547 hours of operation was logged during this period. The test run was terminated prematurely because of excessive vibration of the I.D. booster fan. During the test run the unit operated at approximately 89% of design capacity (design capacity is 163 MW). Inlet SO_2 concentrations ranged from 1000 ppm to 2500 ppm. SO_2 removal efficiencies were approximately 90 to 93%. Particulate loading at the scrubber outlet was 1 g/100 kg (0.01 lb/1000 lb) of flue gas [below the current standards of 15 g/100 kg (0.15 lb/1000 lb) of flue gas]. Sulfur content of the coal ranged from 1.0 to 3.5%. Calculated average stoichiometry for the test run based on SO_2 removed was 1.2. Inspection after shutdown revealed no significant buildup of scale or sludge in the Lurgi venturi scrubbers or the spray tower absorbers. Very slight deposits on the periphery of the interface trays and demisters did not affect system operation. Vibration of the I.D. booster fan was apparently caused by damage to the fan blades by loose fan spray nozzles.
Jan. 76 Feb. 76 Mar. 76 Apr. 76 May 76	St. Clair qualification run and final acceptance tests	The 30-day system supplier qualification run and final acceptance test programs were completed by May 29. The system supplier qualification run was conducted using plant personnel exclusively. The final acceptance test program lasted one week, consisting of SO_2 and particulate removal at various boiler loads. All design guarantees were exceeded on high-sulfur coal application [SO_2 removal efficiency was 90.9% and outlet particulate emissions were measured at 2 g/100 kg (0.02 lb/1000 lb) of flue gas].

(continued)

Table 11 (continued).

Period	Operations	Comments
June 76 July 76 Aug. 76 Sept. 76 Oct. 76	St. Clair SO_2 demonstration program	The in-house scrubber demonstration program began on October 14 and continued for 10 days until excessive vibration and imbalance in the I.D. booster fan assembly forced a scrubber outage. This was caused by sludge and scale carry-over from the wash tray and mist eliminator. The I.D. fan was cleaned out, rebalanced, and its spray system modified for greater capacities.
Nov. 76		System availability index for November was 80%. Outage time was primarily attributed to procuring sand blasting services for removal of the particulate buildup on the I.D. booster fan blades. The sand blasting operation required only 8 hours.
Dec. 76		The availability index for December was 51%. Four forced scrubber outages were caused by malfunction of the dense slurry traverse pump, plugging of the pH sample line, and malfunction of the dense slurry storage tank agitators. SO_2 removal operations are being conducted on flue gases resulting from the burning of low-sulfur western coal.
Jan. 77 Feb. 77 Mar. 77 May 77 June 77 July 77 Aug. 77 Sept. 77	Shutdown for modifications	The SO_2 removal program was concluded on December 31, 1976. The system was removed from the flue gas path for modifications prior to restart in the fall. Modifications will allow operation to remove particulate matter only. Compliance with SO_2 regulations will be achieved by burning low-sulfur western coal. For particulate removal, the trains will remain intact and no solution will be circulated through the spray zone of spray towers. Limestone requirements will be reduced to levels required for pH control only. Some SO_2 removal (30-50%) will occur because of the fly ash alkalinity and that imparted to the scrubbing solution by the limestone.
Oct. 77	St. Clair particulate scrubbing	Scrubbing operations were resumed on October 13, 1977.

of solids from the wash tray because of inefficient operation of the mist eliminator.

The major problems with the St. Clair scrubbing system are highlighted below.

Process Control Network

The pH probes originally specified for service were an in-line type supplied by Foxboro. The failure rate was high because of plugging and blowouts. Conversion to a dip-type probe manufactured by Cambridge has considerably reduced pH monitor problems and maintenance requirements.

The design premise of the system's control network appears faulty. When pH of the solution in the recirculation tank drops below the control range (5.8 to 6.0), the sensor signals the control valve for addition of fresh alkali slurry (limestone, 35 percent solids) to the tank. When the solids content of the solution apparently exceeds 15 percent, however, the sensor signals the control valve for addition of fresh water to the tank. The result is a temporary water imbalance, corrected by overflow into the slurry sump. Because this overflow contains large amounts of unused calcium carbonate, the operation becomes uneconomical and inefficient.

Gas Flow Balance

Balancing the flow of flue gas to the two scrubbing trains has presented problems. No gas flow meters were included in the flue gas ducts to determine the actual gas flow. In operation the design values of gas flow and pressure drop were maintained in one scrubber train, and the remaining gas flowed through the second scrubber train. The resulting imbalance caused a drastic decline in system performance. The utility rectified the problem by installing a flow-balancing "black box" device of their own design.

Fan Vibration

Excessive fan vibration and resulting problems with fan balance have occurred often, usually followed by cleanout and rebalancing. The utility plans to modify the fan's wash system to provide greater water flow and thus increase efficiency of the wash system.

Scale Formation and Plugging

As mentioned earlier, scale formation and plugging have occurred because of control system inadequacies and the inefficiency of various internal components. The most susceptible components have been the booster fan assembly, mist eliminator, and wash water tray.

SYSTEM ECONOMICS

Table 12 summarizes the total installed capital costs of the St. Clair Unit 6 FGD system. The total cost, $13,088,000 (in 1975 dollars), includes $8,151,000 for direct costs and $4,927,000 for indirect costs. Based on the net generating capacity (163 MW) of the boiler equipped with the scrubbing system, this cost equals approximately $80.5/kW. The total includes the particulate removal equipment and sludge disposal capacity for 1 year of operation. Although the utility has provided operating cost estimates, these figures are not included because they do not accurately reflect the demonstration basis upon which this system was operated.

FUTURE OPERATIONS

Sulfur dioxide removal was terminated following completion of the internal demonstration program. The utility is continuing to operate the scrubbing system in the particulate removal mode. Some limestone must be added to the scrubbing solution to prevent low pH swings and subsequent corrosion of internal components. The limestone addition, coupled with the alkalinity of the collected fly ash, should result in some sulfur dioxide removal, in the range of 35 to 50 percent. No tests have been conducted to determine the actual removal efficiency.

Table 12. ST. CLAIR DEMONSTRATION FGD SYSTEM:

TOTAL INSTALLED CAPITAL COSTS[a]

Items	Costs $ (1975)			
Direct cost	Equipment	Installation	Total	$/kW[b]
Raw material handling	213,000	271,000	484,000	
Scrubber, reheater	3,188,000	1,528,000	4,716,000	
Solids disposal[c]	162,800	207,200	370,000	
Solids disposal transport system	212,520	270,480	483,000	
Utilities and services	56,000	72,000	127,000	
Structures, yard facilities, electrical ducts insulation, start-up	867,000	1,103,000	1,970,000	
Direct cost - subtotal	4,699,320	3,451,680	8,151,000	50.2
Indirect cost				
Engineering			2,822,000	
Construction field expense			435,000	
Interest (8.4%) and property tax			1,100,000	
Allowance for start-up			500,000	
Contingency			80,000	
Indirect cost - subtotal			4,927,000	30.3
Total capital cost			13,088,000	80.5[d]

[a] All figures are 1975 dollars.

[b] Based upon the net generating capacity of one-half of the No. 6 unit, 162.5 MW.

[c] One year capacity.

[d] Particulate removal equipment included.

Currently, the utility plans to operate the scrubbing system for 3 to 4 years in the particulate removal mode. The scrubbers will then be shut down and dismantled and eventually replaced with a full-load high-efficiency electrostatic precipitator.

APPENDIX A

PLANT SURVEY FORM

A. Company and Plant Information

1. Company name: Detroit Edison Company
2. Main office: 2000 Second Ave., Detroit, Michigan
3. Plant name: St. Clair Power Plant
4. Plant location: Belle River, Michigan
5. Responsible officer: B.H. Schneider
6. Plant manager: R.W. Berta
7. Plant contact: James E. Meyers
8. Position: Program Director, St. Clair FGD Demonstration Program
9. Telephone number: (313)/237-9284
10. Date information gathered: 3/26/76

Participants in meeting	Affiliation
James E. Meyers	Detroit Edison
Thomas Morasky	Detroit Edison
Charles Dene	Detroit Edison
Gregory Truchan	Detroit Edison
George Gordon	Peabody Engineered Systems, Inc.
Carlton Johnson	Peabody Engineered Systems, Inc.
H.A. Ohlgren	PEDCo
G.A. Isaacs	PEDCo
B.A. Laseke	PEDCo
R.I. Smolin	PEDCo

B. Plant and Site Data

1. UTM coordinates: ______

2. Sea level elevation: Sea level (plant is located beside the St. Clair River)

3. Plant site plot plant (Yes, No): No
(include drawing or aerial overviews)

4. FGD system plan (yes, No): No

5. General description of plant environs: Highly industrialized.

6. Coal shipment mode: Decker coal leaves the mine in Burlington-Northern trains and arrives at the Superior, Wisconsin, coal storage terminal, where it is transferred to two 39,463-Mg (43,500-ton) coal barges and transported through Lakes Superior and Huron to St. Clair, Michigan. The water is navigable only 8 or 9 months of the year.

C. FGD Vendor/Designer Background

1. Process name: Limestone scrubbing

2. Developer/licensor name: Peabody Engineered Systems

3. Address: 39 Maple Tree Avenue
Stamford, Connecticut

4. Company offering process:

Company name: Peabody Engineered Systems

Address: 39 Maple Tree Avenue

Location: Stamford, Connecticut

Company contact: Carlton A. Johnson

Position: Manager of Process Engineering

Telephone number: (203)/327-700

5. Architectural/engineers name: Bechtel

Address:

Location: Ann Arbor, Michigan

Company contact:

Position:

Telephone number:

D. Boiler Data

1. Boiler: Unit No. 6

2. Boiler manufacturer: Combustion Engineering

3. Boiler service (base, standby, floating, peak):

Peak load service

4. Year boiler placed in service: 1961

5. Total hours operation: Approximately 85,000

6. Remaining life of unit: Approximately 15 years

7. Boiler type: Two-stage superheater unit containing two boiler boxes

8. Served by stack no.: 6

9. Stack height: 130 m (425 ft)

10. Stack top inner diameter:

11. Unit ratings (MW):

Gross unit rating: 325 MW total; 50% to scrubber

Net unit rating without FGD: 163 MW

Net unit rating with FGD: 6.6 MW lost on No. 6

Name plate rating: 350 MW

12. Unit heat rate: 9918 kJ/net kWh (9400 Btu/net kWh)

Heat rate without FGD:

Heat rate with FGD: 9400 (net)

13. Boiler capacity factor, (1974): 73.5%

14. Fuel type (coal or oil): Coal

15. Flue gas flow: 466 m^3/sec (987,000 acfm)

Maximum: 466 m^3/sec (987,000 acfm)

Temperature: 132°C (270°F)

16. Total excess air: 15-20

17. Boiler efficiency:

E. Coal Data

1. Coal supplier:

Name: Decker Coal Company

Location: Montana

Mine location: Dietz Mine

County, State: Southern portion of Montana

Seam: No. 1

2. Gross heating value: 15,513 Mg/wk (17,100 ton/wk) (1974 consumption)

3. Ash (dry basis): 3.0 to 4.0

4. Sulfur (dry basis): 0.3 to 0.4

5. Total moisture: 22.0 to 24.0

6. Chloride: N/A

7. Ash composition (See Table A1) N/A

Not Available

Table A1

Constituent	Percent weight
Silica, SiO_2	
Alumina, Al_2O_3	
Titania, TiO_2	
Ferric oxide, Fe_2O_3	
Calcium oxide, CaO	
Magnesium oxide, MgO	N/A
Sodium oxide, Na_2O	
Potassium oxide, K_2O	
Phosphorous pentoxide, P_2O_5	
Sulfur trioxide, SO_3	
Other	
Undetermined	

F. Atmospheric Emission Regulations

1. Applicable particulate emission regulation

   a) Current requirement: 86 mg/J (0.20 lb/10^6 Btu)

      AQCR priority classification: ____________

      Regulation and section No.: MI/R 336.49

   b) Future requirement (Date:): ____________

      Regulation and section No.: ____________

2. Applicable SO_2 emission regulation

   *a) Current requirement: 1.0% sulfur fuel content

      AQCR Priority Classification: ____________

      Regulation and section No.: ____________

   b) Future requirement (Date:) ____________

* 1978 State emission limitation.

Regulation and section No.: MI/R 336.49

G. Chemical Additives: (Includes all reagent additives - absorbents, precipitants, flocculants, coagulants, pH adjusters, fixatives, catalysts, etc.)

1. Trade name: Limestone

   Principal ingredient: $CaCO_3$; 1% MgO

   Function: SO_2 Absorbent

   Source/manufacturer: Levy Co., Jefferson-Marine Terminal, Rogers City, Michigan

   Quantity employed: 26,308 Mg (29,000 ton)/year based on 1.6% sulfur coal

   Point of addition: Recirculation tank

2. Trade name: Not applicable

   Principal ingredient:

   Function:

   Source/manufacturer:

   Quantity employed:

   Point of addition:

3. Trade name: Not applicable

   Principal ingredient:

   Function:

   Source/manufacturer:

   Quantity employed:

   Point of addition:

4. Trade name: Not applicable

   Principal ingredient:

   Function:

   Source/manufacturer:

   Quantity employed:

Point of addition: __________

5. Trade name: Not applicable

Principal ingredient: __________

Function: __________

Source/manufacturer: __________

Quantity employed: __________

Point of addition: __________

H. Equipment Specifications

1. Electrostatic precipitator(s)

Number: Two

Manufacturer: Wheelebrator-Frye

Particulate removal efficiency: 90

Outlet temperature: 132°C (270°F)

Pressure drop: __________

2. Mechanical collector(s) (yes)

Number: __________

Type: __________

Size: __________

Manufacturer: __________

Particulate removal efficiency: __________

Pressure drop: __________

3. Particulate scrubber(s)

Number: Two , one per scrubbing train

Type: Radian Flow Venturi

Manufacturer: Peabody-Lurgi

Dimensions: __________

Material, shell: 316L SS

Material, shell lining: Rubber

Material, internals: 316L SS (quench and orifice sections)

No. of modules: One

No. of stages: One

Nozzle type: Bull nozzle

Nozzle size:

No. of nozzles:

Boiler load: 50% (total boiler gas flow)

Scrubber gas flow: 117 m^3/sec 132°C (247,000 acfm, 230°F)

Liquid recirculation rate: 279 l/sec (4420 gal./min)

Modulation: Stepwise shutdown of recirculation pumps

L/G ratio: 2.4 l/m^3 (20 gal./1000 acf)

Scrubber pressure drop: 3.5 kPa (14 in. H_2O)

Modulation: None

Superficial gas velocity: 28 m/sec (93 ft/sec)

Particulate removal efficiency: 99.7% overall

Inlet loading: 8.2 g/m^3 (3.6 gr/scf)

Outlet loading:

SO_2 removal efficiency: 35-50%

Inlet concentration: 3000 ppm (maximum)

Outlet concentration: 1500-2000 ppm

4. SO_2 absorber(s)

Number: Two, one per scrubbing train

Type: High-velocity countercurrent spray tower

Manufacturer: Peabody Engineered Systems

Dimensions: ______

Material, shell: 316L SS

Material, shell lining: None

Material, internals: None

No. of modules: One

No. of stages: One

Packing type: None

Packing thickness/stage: None

Nozzle type: Silicon carbide hollow cone

Nozzle size: ______

No. of nozzles: 6 banks of nozzles/tower

Boiler load: 50% (total boiler gas flow)

Absorber gas flow: 101 m^3/sec, 48°C (215,000 acfm, 118°F)

Liquid recirculation rate: 372 l/sec (5900 gal/min)

Modulation: Stepwise shutdown of recirculation pumps

L/G ratio: 11 l/m^3 (80 gal/1000 acf)

Absorber pressure drop: 2.5 kPa (10 in. H_2O)

Modulation: None

Superficial gas velocity: 2.9 m/sec (9.5 ft/sec)

Particulate removal efficiency: 99.7% overall

Inlet loading: ______

Outlet loading: 0.02 g/m^3 (0.01 gr/scf)

SO_2 removal efficiency: 90%

Inlet concentration: 1500-2000 ppm

Outlet concentration: 300 (max.) ppm

5. Clear water tray(s)

Number: Two, one per absorber

Type: Impingement wash tray

Materials of construction: 316L SS

L/G ratio:

Source of water: Wash water recycle tank

6. Mist eliminator(s)

Number: Two, one per absorber

Type: Radial baffle - curved vane

Materials of construction: 316L SS

Manufacturer: Peabody

Configuration (horizontal/vertical): Horizontal

Distance between scrubber bed and mist eliminator:

1.4 m (4.5 ft)

Mist eliminator depth:

Vane spacing: 20 cm (8 in) at top center; 30 cm (12 in.) at bottom rim.

Vane angles: 30 to 45°

Type and location of wash system: None, mist eliminators preceded by fresh water wash trays

Superficial gas velocity: 5 m/sec (10 ft/sec)

Pressure drop: 0.05 kPa (0.2 in. H_2O) 46.5 kPa (3.0 in. H_2O) for wash tray

Comments:

7. Reheater(s): One

Type (check appropriate category):

- [ ] in-line
- [ ] indirect hot air
- [x] direct combustion
- [ ] bypass
- [ ] exit gas recirculation
- [ ] waste heat recovery
- [ ] other

Gas conditions for reheat:

Flow rate: 186 m^3/sec (396,700 acfm)

Temperature: 50°C (122°F)

SO_2 concentration: 200 ppm

Heating medium: Combustion gases

Combustion fuel: No 6 fuel oil

Percent of gas bypassed for reheat: None

Temperature boost (ΔT): 121-149°C (250-300°F)

Energy required: 4.4%

Comments: The reheater combustion chamber is located outside the main duct. The combustion products are injected into the main gas stream through a diffuser.

8. Fan(s)

Type: Wet

Materials of construction: 316L SS

Manufacturer: Peabody

Location: Between mist eliminator and reheater unit

Fan/motor speed: N/A

Motor/brake power: N/A

Variable speed drive: N/A

9. Tank(s) One recirculation

Materials of construction: Carbon steel/ceilcote lining

Function: Liquid recirculation/alkali addition/waste disposal

Configuration/dimensions: Cylindrical 14.6 m x 11.6 m (48 ft) x (38 ft)

Capacity: 1,949,487 l (515,000 gal)

Retention times: 10 minutes

Covered (yes/no): No

Agitator description: 4 agitators

10. Recirculation/slurry pump: service description

No.		Manufacturer	Capacity l/sec (gal/min)	Operation
2	Slurry feed	Denver	14 (215)	Full time
3	Venturi recycle	Denver	279 (4,420)	One spare
6	Absorber recycle	Denver	372 (5,900)	One spare

11. Thickener(s)/clarifier(s)

Number: Not applicable

Type:

Manufacturer:

Materials of construction:

Configuration:

Diameter:

Depth:

Rake speed:

12. Vacuum filter(s)

Number: Not applicable

Type:

Manufacturer:

Materials of construction:

Belt cloth material:

Design capacity:

Filter area:

13. Centrifuge(s)

Number: Not applicable

Type:

Manufacturer:

Materials of construction:

Size/dimensions:

Capacity:

14. Interim sludge pond(s)

Number: One

Description: Sludge disposal pond

Area: 43,706 m^2 (10.8 acres)

Depth: 3 m (10 feet)

Liner type: Diked settling pond, clay lined.

Location: 488 m (1600 ft) from plant

Typical operating schedule: 19 Mg/hr (21 tons/hr) (dry); 142 Mg (156 tons) produced per ton of coal consumed (dry).

Ground water/surface water monitors: None

15. Final disposal site(s)

Number: See interim sludge ponds

Description:

Area:

Depth:

Location:

Transportation mode:

Typical operating schedule:

16. Raw materials production

Type: Reagent received prepared

Number: 1 storage silo

Manufacturer:

Capacity: 680 Mg (750 tons)

Product characteristics: Limestone slurry storage capacity is 568,000 l (150,000 gal.);

I. Equipment Operation, Maintenance, and Overhaul Schedule

1. Scrubber(s)

Design life:

Elapsed operation time:

Cleanout method:

Cleanout frequency:

Cleanout duration:

Other preventive maintenance procedures:

2. Absorber(s)

Design life: ____________________

Elapsed operation time: ____________________

Cleanout method: ____________________

Cleanout frequency: ____________________

Cleanout duration: ____________________

Other preventive maintenance procedures: ____________________

____

3. Reheater(s)

Design life: ____________________

Elapsed operation time: ____________________

Cleanout method: ____________________

Cleanout frequency: ____________________

Cleanout duration: ____________________

Other preventive maintenance procedures: ____________________

____

4. Scrubber fan(s)

Design life: ____________________

Elapsed operation time: ____________________

Cleanout method: ____________________

Cleanout frequency: ____________________

Cleanout duration: ____________________

Other preventive maintenance procedures: ____________________

____

5. Mist eliminator(s)

Design life: ____________________

Elapsed operation time: ____________________

Cleanout method: ______

Cleanout frequency: ______

Cleanout duration: ______

Other preventive maintenance procedures: ______

______

6. Pump(s)

Design life: ______

Elapsed operation time: ______

Cleanout method: ______

Cleanout frequency: ______

Cleanout duration: ______

Other preventive maintenance procedures: ______

______

7. Vacuum filter(s)/centrifuge(s)

Design life: ______

Elapsed operation time: ______

Cleanout method: ______

Cleanout frequency: ______

Cleanout duration: ______

Other preventive maintenance procedures: ______

______

8. Sludge disposal pond(s)

Design life: ______

Elapsed operation time: ______

Capacity consumed: ______

Remaining capacity: ______

Cleanout procedures: ______________________

____

J. Cost Data

1. Total installed capital cost: $8,151,000

2. Annualized operating cost: Not available

3. Cost analysis (see breakdown: Table A2)

4. Unit costs

   a. Electricity: ______________________

   b. Water: ______________________

   c. Steam: ______________________

   d. Fuel (reheating/FGD process): ______________________

   e. Fixation cost: ______________________

   f. Raw material: ______________________

   g. Labor: ______________________

5. Comments A detailed capital cost analysis is provided in the text of the report, Section 4 and Table A2 . Annualized operating costs are not provided because of their meaningless nature (i.e. the system was in service only for a 2.5 month demonstration program).

Table A2. COST BREAKDOWN

Cost elements	Included in cost estimate		Estimated amount or % of total capital cost
	Yes	No	
A. Capital Costs			
Scrubber modules	☐	☐	______
Reagent separation facilities	☐	☐	______
Waste treatment and disposal pond	☐	☐	______
Byproduct handling and storage	☐	☐	______
Site improvements	☐	☐	______
Land, roads, tracks, substation	☐	☐	______
Engineering costs	☐	☐	______
Contractors fee	☐	☐	______
Interest on capital during construction	☐	☐	______
B. Annualized Operating Cost			
Fixed Costs			
Interest on capital	☐	☐	______
Depreciation	☐	☐	______
Insurance and taxes	☐	☐	______
Labor cost including overhead	☐	☐	______
Variable costs			
Raw material	☐	☐	______
Utilities	☐	☐	______
Maintenance	☐	☐	______

K. Instrumentation

A brief description of the control mechanism or method of measurement for each of the following process parameters:

- Reagent addition: ______________________________

  ____

- Liquor solids content: ______________________________

  ____

- Liquor dissolved solids content: ______________________________

  ____

- Liquor ion concentrations

  Chloride: ______________________________

  ____

  Calcium: ______________________________

  ____

  Magnesium: ______________________________

  ____

  Sodium: ______________________________

  ____

  Sulfite: ______________________________

  ____

  Sulfate: ______________________________

  ____

  Carbonate: ______________________________

  ____

  Other (specify): ______________________________

  ____

° Liquor alkalinity: ______________________

____

° Liquor pH: ______________________

____

° Liquor flow: ______________________

____

° Pollutant (SO_2, particulate, NO_x) concentration in flue gas: ______________________

____

° Gas flow: ______________________

____

° Waste water ______________________

____

° Waste solids: ______________________

____

Provide a diagram or drawing of the scrubber/absorber train that illustrates the function and location of the components of the scrubber/absorber control system.

Remarks: Detailed information on the control system is given in the report, Section 3, and Figure 4.

____

____

____

L. Discussion of Major Problem Areas: See text, Section 4 and Table 10.

1. Corrosion: ______________________

____

____

2. Erosion:

3. Scaling:

4. Plugging:

5. Design problems:

6. Waste water/solids disposal:

7. Mechanical problems:

M. General comments:

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-78-048c	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Survey of Flue Gas Desulfurization Systems: St. Clair Station, Detroit Edison Co.		5. REPORT DATE March 1978
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Bernard A. Laseke, Jr.		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS PEDCo Environmental, Inc. 11499 Chester Road Cincinnati, Ohio 45246		10. PROGRAM ELEMENT NO. EHE624
		11. CONTRACT/GRANT NO. 68-01-4147, Task 3
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Subtask Final; 1-6/77
		14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer is Norman Kaplan, Mail Drop 62, 919/541-2556.

16. ABSTRACT The report gives results of a survey of the flue gas desulfurization (FGD) system retrofitted on Unit 6 of Detroit Edison Co.'s St. Clair Station. The experimental FGD system, which operated through a 2-month (October 1976-January 1977) demonstration program, utilized a limestone slurry to remove SO2 in two parallel scrubbing trains. Each train included a radial-flow venturi scrubber and a high-velocity countercurrent spray tower absorber to control Fly ash and SO2. Flue gas cleaning wastes were discharged from a reaction tank to an on-site clay-lined settling pond. Clear water was recycled from the pond to the FGD system for further use. The FGD system was designed to remove SO2 and fly ash from high sulfur eastern coal. Actual operation was on low sulfur western coal. Following the demonstration, the FGD system was shut down and modified for resumption of particulate scrubbing on low sulfur western coal in the fall of 1977. Some SO2 is removed from the flue gas during particulate removal because of the alkalinity of the collected fly ash and the limestone additive used for pH control of the scrubbing solution.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Air Pollution	Scrubbers	Air Pollution Control	13B	
Flue Gases	Coal	Stationary Sources	21B	21D
Desulfurization	Combustion	Wet Limestone	07A,07D	
Fly Ash	Cost Engineering	Particulate		14A
Limestone	Sulfur Dioxide			07B
Slurries	Dust Control		11G	
Ponds			08H	

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 64
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE