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SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS: GREEN RIVER STATION, KENTUCKY UTILITIES

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by

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SUMMARY

Kentucky Utilities (KU) contracted with American Air Filter (AAF) to design and install a system for removal of sulfur dioxide and particulate from flue gases of three boilers at the Green River Power Station. The flue gas desulfurization (FGD) and particulate removal system consists of one wet lime scrubber module designed to handle a maximum of 170 acms (360,000 acfm) of flue gas at 149°C (300°F). The scrubber module contains a variable-throat venturi with a flooded elbow for fly ash removal, and a mobile-bed contactor for sulfur dioxide removal. Entrained water droplets are removed from the scrubbed gases by means of a radial-vane mist eliminator before discharge to a local stack. Mechanical collectors upstream of the wet scrubbing system remove primary particulate matter.

The boilers (1, 2, and 3) are pulverized-coal-fired units servicing two turbines, each rated at 32 MW (gross). The fuel burned in these units is primarily a high-sulfur Western Kentucky coal [25 MJ/kg (10,800 Btu/lb), 3.8 to 4.0 percent sulfur, 14 percent ash]. Flue gases can bypass the scrubbing system through a system of ductwork and guillotine dampers.

In June 1973 KU awarded a turnkey contract to AAF, who completed construction and installation of the system by mid-summer 1975. After general electrical and mechanical debugging, the unit was put in service on air and water only in August 1975; in the ensuing period, operators monitored gas and liquid flows, operation of dampers, and spray patterns, and performed the required calibrations. The system was then operated on air and water under normal process conditions to allow detection of any early mechanical failures before the initial flue gas run.

The flue gas run began on September 13, 1975. Initial operation was at half load because one of the turbine generators was out of service for overhaul and repairs. The scrubbing system was operated on an open water loop. This mode (half-load, open-loop) continued until March 1976, when the system began operation at full load and closed water loop. Operation has proceeded in this manner since that date. During the remainder of 1976 the system underwent a 6-month supplier qualification run under the auspices of AAF. FGD system availability* in 1976 was 85.4 percent; system service time totalled 6045.94 hours at an average unit load factor of 47.5 percent.

The service times reported for the power-generating unit and the scrubber in 1977 are substantially lower than the 1976 levels because of a unit shutdown in February and March for stack and boiler repairs and a plant operator strike from June to October. FGD system availability in 1977 (through November) was 78.5 percent; system service time totalled 1963.66 hours at an average unit load factor of 15.2 percent.

Data on the facility and FGD system are summarized in Table 1.

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

Table 1. DATA SUMMARY: GREEN RIVER FACILITY AND FGD SYSTEM

Boilers	1, 2, and 3
Total capacity (gross), MW	64
Fuel	Pulverized coal
Average fuel characteristics	
Heating value, MJ/kg (Btu/lb)	25 (10,800)
Sulfur, percent	3.9
Ash, percent	13.4
Total moisture, percent	12.1
FGD system supplier	American Air Filter
Process	Wet lime scrubbing
Type	Retrofit
Modules	One
Status	Operational
Start-up date	9/75
Design efficiency, percent overall	
Sulfur dioxide	80
Particulate	99.7[a]
Makeup water, (l/sec)/MW (gpm/MW)	0.08 (1.2)
Sludge disposal	Unstabilized sludge disposed in on-site, clay-lined pond
Unit cost	
Capital, $/kW	57.4
Annual, mills/kWh	2.02

[a] This value includes particulate removal provided by the existing mechanical collectors.

SECTION 1

INTRODUCTION

The Industrial Environmental Research Laboratory (IERL) of the U.S. Environmental Protection Agency (EPA) has initiated a study to evaluate 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 lime scrubbing system developed by American Air Filter (AAF) and installed at the Green River Station of the Kentucky Utilities Co. (KU). It is based on information obtained during and after plant inspections conducted on March 3, 1976; June 30, 1976; and March 22, 1977. The information is considered valid as of November 1977.

Section 2 presents information and data on the plant environs and facilities. Section 3 provides a detailed description of the FGD system, and Section 4 analyzes the performance of the system to date. Appendices present details of plant and system operation and photos of the installation.

SECTION 2

FACILITY DESCRIPTION

The Green River Station of KU is on the Green River in central Kentucky, approximately five miles north of Central City. The terrain surrounding the power plant is sparsely populated and heavily wooded. A number of strip mines are located there.

The plant contains four steam turbine generating units having a total gross generating capacity of 242 MW. Boilers 1, 2, and 3 supply steam for two of the steam turbine generators with a combined generating capacity of 64 MW. Because these two electrical generating units are used only for peak loads, the three boilers normally operate on a 5-day week, with one or more often at reduced capacity.

All three boilers are dry-bottom, pulverized-coal-fired units, manufactured by Babcock and Wilcox and put in service in 1949 and 1950. At present, KU has no plans to retire these units.

The plant burns coal from two sources. A low-sulfur grade, generally averaging less than 1.0 percent sulfur by weight, comes from the Hoyt Mine, in Hazard, Harlan County, Kentucky, and is shipped to the plant by truck and rail. The utility also purchases a high-sulfur coal, which is used with the FGD system. This coal is from the Drake Mine in Muhlenberg County, Kentucky, and is shipped to the plant by barge. A typical analysis of the Drake Mine coal gives the following values: heating value, 25 MJ/kg (10,800 Btu/lb); sulfur content, 3.9 percent; ash content, 13.4 percent; total moisture, 12.1 percent.

Boilers 1, 2, and 3 are fitted with mechanical collectors upstream from the FGD system. Design efficiency for particulate removal is 85 percent. The FGD system, designed and installed by AAF, consists of one scrubber module to handle a maximum flue gas capacity of 169 m^3/sec (360,000 acfm) at 149°C (300°F). Table 2 gives data on plant design, operation, and atmospheric emissions.

Table 2. DESIGN, OPERATION, AND EMISSION DATA,

GREEN RIVER BOILERS 1, 2, AND 3

Total rated generating capacity, MW	64
Boiler manufacturer	Babcock & Wilcox
Year placed in service	1949, 1950
Unit heat rate, kJ/net kWh	13,990
Btu/net kWh	13,250
Coal consumption, Gg/week	1285
short ton/week	1,416 x 10^3
Maximum heat input, GJ/hr	895
10^6 Btu/hr	848
Stack height above grade, m	50
ft	165
Design maximum flue gas rate,	
Nm^3/hr (0°C)	396,000
scfm (70°F)	251,000
acfm	360,000
Flue gas temperature, (FGD inlet) °C (°F)	149 (300)
Emission controls:	
Particulate	Mechanical collector and venturi scrubber
Sulfur dioxide	Venturi scrubber and mobile-bed contactor
Particulate emission rates:	
Allowable, ng/J (lb/10^6 Btu)	42[a] (0.097)
Actual, ng/J (lb/10^6 Btu)	Undetermined
Sulfur dioxide emission rates:	
Allowable, ng/J (lb/10^6 Btu)	724[a] (1.67)
Actual, ng/J (lb/10^6 Btu)	Undetermined

[a] Emission level at full load.

SECTION 3

FLUE GAS DESULFURIZATION SYSTEM

PROCESS DESCRIPTION

The wet lime scrubbing system installed at the Green River Power Station incorporates a mobile-bed contactor unit for removal of sulfur dioxide from flue gases. American Air Filter designed and installed this single-module scrubbing system to handle flue gas generated by coal burned in three dry-bottom, pulverized-coal boilers. The process is conveniently described in terms of two basic operations: a tail-end flue gas scrubbing system, and a lime slurry/recycle system. Figure 1 provides a schematic flow diagram of the process.

Flue Gas Scrubbing System

The flue gas from each boiler passes first through a series of mechanical collectors [Western Precipitation, multicyclone, 23-cm (9-in.)-diameter, cast iron construction] that remove particulates. The flue gas is then drawn from the breeching, through a guillotine-type isolation damper and associated ductwork, to the scrubber fan. By use of the isolation dampers operators can selectively allow flue gases to bypass the scrubbing system and pass directly to an existing stack.

Prior to entering the scrubbing system, the flue gas passes through a 1120-W (1500-hp), 4482-Pa (18-in. H_2O), forced-draft booster fan. This fan maintains zero pressure upstream of the fan through damper control to prevent back pressure on the boilers. From the outlet of the scrubber booster fan, the gas flows through a variable-throat venturi scrubber with flooded elbow. These components provide additional capability for removal of particulate matter escaping the upstream mechanical collectors,

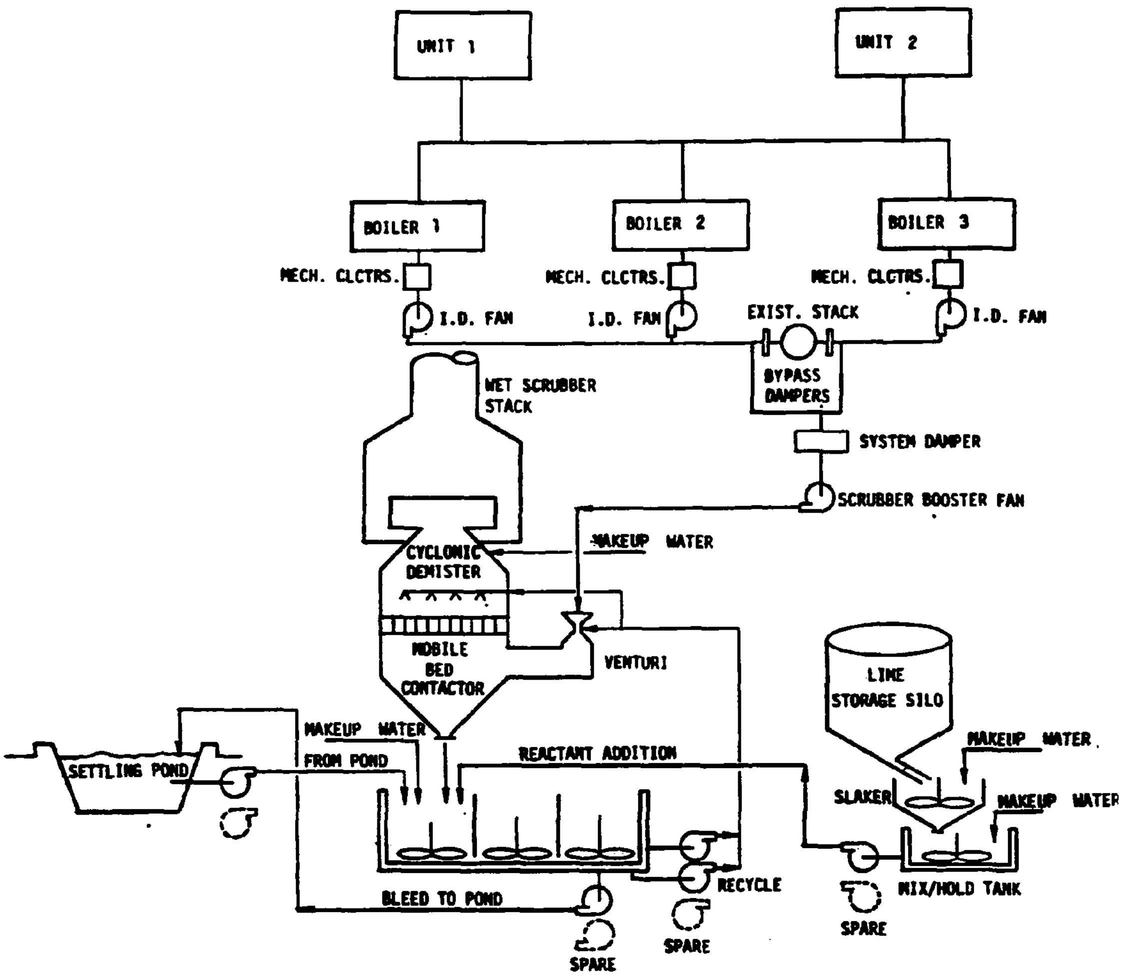


Figure 1. Original process flow diagram, Green River FGD system.

and also effect initial quenching of the hot gas. Quenching lowers the temperature of the inlet gas from 163°C (325°F) (actual) to approximately 52°C (126°F) within the scrubber module. This reduction causes a substantial decrease in the volume of gas to be scrubbed and provides protection to the plastic spheres used in the mobile-bed contactor.

Pressure drop through the venturi is maintained at 1743 Pa (7 in. H_2O) by a limitorque operator on the plug. Liquid flow through the top of the scrubber is maintained at 83 l/sec (1360 gpm). The scrubber shell is constructed of mild steel and lined with acid-proof precrete. The venturi throat is constructed of stainless steel. From the venturi the gas passes through the flooded elbow and flows upward through the mobile-bed contactor at a rate of 135 m^3/sec at 52°C (288,200 acfm at 126°F). The absorber is constructed of mild steel and lined with acid-proof refractory. It contains approximately 175,000 to 190,000 solid spheres made of polyvinyl chloride and polyethylene, which provide the surface needed to facilitate reaction of the sulfur dioxide in the flue gas with the lime slurry. The slurry is fed at a rate of 595 l/sec (9750 gpm) and is applied both to the bed and to the upward rising flue gas by overhead nozzles and by sphere return nozzles spraying upward. The contactor bed is compartmentalized into individual sections. Underbed dampers are used to adjust for flue gas turndown requirements. Pressure drop through the contactor bed is approximately 996 Pa (4 in. H_2O).

Following passage through the bed, the gases continue upward 8.38 m (27.5 feet) to the single-stage, single-pass radial-vane mist eliminator. The turning vanes are curved and constructed of stainless steel. The outside collection area is constructed of coated mild steel. The mist eliminator depth and vane spacing are approximately 0.9 m (3 feet). The mist eliminator is continuously washed by outward spraying nozzles at a rate of 3 l/sec (50 gpm) total. Pressure drop is approximately 498 Pa (2 in. H_2O).

The scrubbed flue gas (139 m^3/sec at 52°C; 296,300 acfm at 126°F) is discharged to the atmosphere through the wet scrubber stack, which is constructed of carbon steel and lined with precrete applied to wire mesh.

Lime Slurry/Recycle System

The scrubbing slurry feed and recycle system consists of a partitioned concrete reactant tank that includes recycle pumps to supply the scrubber and absorber module, a lime slurry slaking and feed system, a bleed system for discharge of scrubbing wastes to a settling pond, and a return water system that recycles water from the settling pond to the process.

Pebble lime (1.9-cm, 0.75-in.) is delivered by rail to the plant site and transferred pneumatically to a 454-Mg (500-ton) capacity storage bin. The storage bin is equipped with a vibrating bottom and a 20-cm (8-in.) screw conveyor, which discharges the lime at a rate of 0.5 kg/sec (2 ton/hr) into a covered slaking tank. Two agitator-equipped slaking tanks have been installed, one of which is used for backup.

From the slaking tank, slurry is discharged through a drag-chain degritter to a mix/hold tank, also equipped with an agitator. Liquid volume capacity of the tank is 7500 l (1980 gal.). The fresh scrubbing slurry, with 20 percent solids content, is trans ferred by pumps to the return section of a reactant tank system installed beneath the scrubbing module.

The reactant tank, constructed of acid-proof concrete, provides a total retention time of more than 20 minutes. Two partitions form three individual compartments connected by underflow openings. Each compartment is equipped with an agitator. The function of each compartment is described below:

- The return section of the reactant tank system receives the reaction products and the collected flyash discharged from the scrubbing module. In addition, fresh lime slurry, fresh makeup water (cleaned river water), or pond return water is supplied to the system at this point.

- The recycle/discharge section of the reactant tank system feeds both the venturi scrubber and mobile-bed contactor with recycled scrubbing solution. Bleed pumps remove the scrubbing wastes from this section of the reactant tank to maintain a slurry solids content of 8 to 12 percent. The bleed stream is discharged to a settling pond, and clear water is pumped from the pond to the return section.
- The third section, situated between the return and recycle sections, was installed as a deliberate redundancy to facilitate surveillance of process chemistry.

Recycle pumps taking slurry by suction from the reactant tank feed both the venturi particulate scrubber and the mobile-bed contactor. These pumps (two operational, one spare) are rated at 360 l/sec (5900 gpm) each. All pumps and agitators are rubber-lined.

Reaction products and collected particulate matter are pumped to an impervious clay-lined pond on the plant site approximately 0.8 km (0.5 mile) from the scrubbing module. Pond capacity is 183,000 m^3 (148 acre-ft) at a depth of 6.1 m (20 ft). It is calculated that this pond will be usable for 9 years and that its capacity is expandable to 511,000 m^3 (414 acre-ft) to provide 20 years of use. For closed loop operation clarified pond water is returned to the reactant tank. Treated river water is used as makeup and is introduced into the reactant tank, lime slaking tank, and mist eliminator as well as to the various pump seals. Total fresh water makeup supplied to the system is 4.6 l/sec (75 gpm).

PROCESS CHEMISTRY: PRINCIPAL REACTIONS

The first and most important step in wet-phase absorption of sulfur dioxide from the flue gas stream is diffusion from the gas to the liquid phase. Sulfur dioxide is an acid anhydride that readily undergoes reaction to an acid and further reaction to hydrogen, bisulfite, and sulfite ions.

$$SO_2 \uparrow \rightleftharpoons SO_2 \text{ (aq.)}$$

$$SO_2 \text{ (aq.)} + H_2O \rightleftharpoons H_2SO_3$$

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

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

$$HSO_3^- + OH^- \rightleftharpoons SO_3^= + H_2O$$

The lime scrubbing solution is first activated by slaking the pebble lime to form calcium and hydroxide ions, as shown in the following equations.

$$CaO \downarrow + H_2O \rightleftharpoons Ca(OH)_2$$

$$Ca(OH)_2 \rightleftharpoons Ca^{++} + 2OH^-$$

The reaction products precipitate as calcium salts, and the scrubbing solution is recycled to the scrubber. The principal mechanisms of product formation and precipitation are as follows:

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

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

Reactions leading to formation of calcium sulfate are briefly summarized as follows:

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

$$SO_3 \uparrow \rightleftharpoons SO_3 \text{ (aq.)}$$

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

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

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

$$HSO_4^+ + OH^- \rightleftharpoons SO_4^= + H_2O$$

$$SO_3^= + 1/2\ O_{2\,(aq.)} \rightleftharpoons SO_4^=$$

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

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

The chemical absorption of sulfur dioxide into the scrubbing solution occurs in the mobile-bed contactor of the scrubbing module. The mobile packing provides a reaction medium that allows good mass transfer at relatively low pressure drops. It also minimizes the probability of solids deposition and plugging because the movement of the spheres prevents the solids from adhering to their surfaces.

The scrubbing solution is maintained in the alkaline range (pH approximately 8.0 to 8.5) as it enters the scrubber module. Contact with the sulfur dioxide in the flue gas and the resulting chemical absorption into the liquid phase causes the solution pH to decrease.

PROCESS CONTROL

Gas and Liquid Flow

Control of gas and liquid flow through the scrubbing system is relatively simple. The flow of the scrubbing solution is maintained at a constant rate, independent of modulation. Gas flow and pressure drop, however, are controllable by means of a limitorque operator in the venturi and a damper system in the absorber. The limitorque operator maintains a constant pressure drop of 1743 Pa (7 in. H_2O) across the venturi. The dampers below the compartments of the mobile bed accommodate gas volume turndown requirements.

Scrubbing Solution Chemistry

The chemistry of the scrubbing solution is controlled automatically in the reactant tank system. Separation of the reactant tank into three compartments permits selective control of feed and discharge streams. The spent scrubbing slurry, fresh reagent, fresh makeup water, pond return water, and bleed streams are transferred through the reactant tank system.

The chemistry of the FGD system is determined primarily by pH of the scrubbing solution, which is monitored in each section of the reactant tank. Six immersion-type pH sensors, two per section, are installed in the reactant tank. Details of the process control system are illustrated in Figure 2 and are outlined as follows.

(1) Spent scrubbing solution is discharged from the absorber into the return section of the reactant tank. A 7-minute residence time allows for near completion of the chemical reactions. During this residence period, the pH of the scrubbing solution is monitored. Generally, the spent solution stabilizes at pH 5.0 to 6.0. After completion of the absorption reactions in the agitated compartment, the solution underflows to the next compartment.

(2) The lime slurry addition to the first compartment is further regulated in the second compartment by an analyzing indicator control system. The pH sensors are used to modulate a flow control valve installed in the lime slurry feed line. This system regulates lime addition as a function of solution pH over a control range with upper and lower limits of 8.5 and 5.0, respectively.

(3) The scrubbing solution then underflows to the third compartment for recycling or discharge to a settling pond. The bleed stream to the settling pond is controlled by one of two nuclear density meters (Ohmart and Texas Nuclear) installed in the recycle line. The control is set at 10 percent solids in the recycle solution. When this value is exceeded, the valve on the bleed line is opened and the scrubbing wastes are pumped to the pond, where solids settle out. Clear water is pumped from the pond to the return section of the reactant tank to maintain water balance through the system.

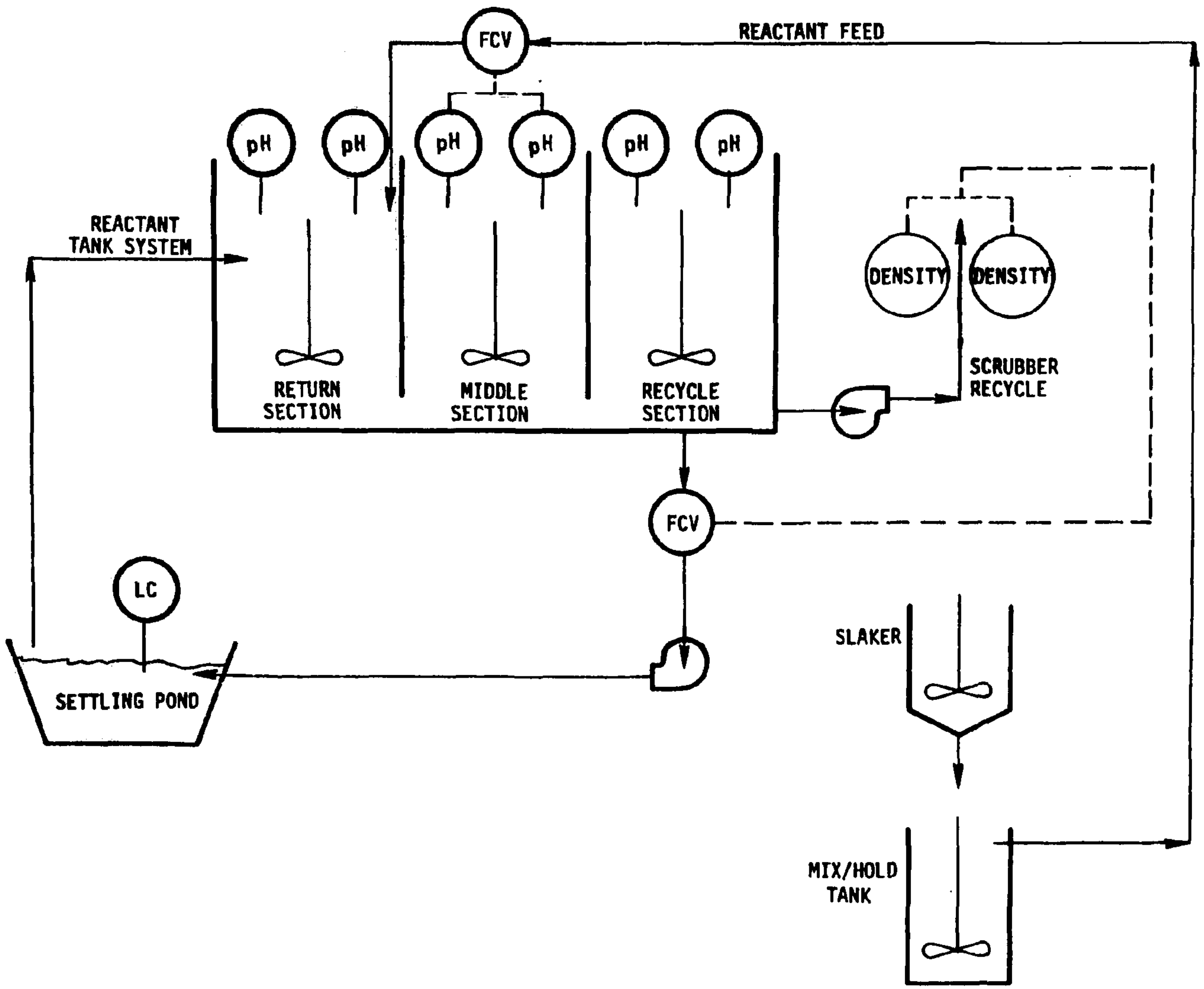


Figure 2. Simplified process instrumentation and control diagram, Green River FGD system.

Water Balance

Recycling of supernatant from the settling pond to the return section of the reactant tank is controlled by a level indicator located in the recycle section. Also, fresh makeup water (cleaned river water) is added to the system through mist eliminator wash (3 l/sec, 50 gpm), pump gland seals, and lime slaking (1.5 l/sec, 25 gpm for both).

SECTION 4

FGD SYSTEM PERFORMANCE

BACKGROUND INFORMATION

Commercial operation of the scrubbing system began in the fall of 1975. Before commercial service, the system was put through an extensive four-phase prestart-up program, which included mechanical and electrical debugging, operation on air and water, verification of mechanical reliability, and operation on hot flue gas. Manpower for these test phases was provided by the system supplier (AAF), the utility (KU), and their mechanical and electrical contractors. The testing activities are summarized below.

Mechanical and Electrical Debugging

The system underwent mechanical and electrical debugging in July 1975. The test program included operation of agitators and pumps and preliminary checks of electrical circuitry.

Air and Water Testing

The air and water test phase, which began in August 1975, consisted primarily of observing gas flows and spray patterns in the scrubbing system. Operation of the mobile-bed contactor was analyzed with respect to sphere movement and nozzle location within the contactor bed. Several system control loops and access points were confirmed or modified, and pipe supports were added.

Mechanical Reliability Testing

The system was operated for 2 weeks to verify mechanical reliability, and minor malfunctions were corrected. The system operated for a short period following addition of gypsum seed crystals to the reactant tank system.

Flue Gas Operation

Initial operation on flue gas began on September 13, 1975. The system was operated at 50 percent load, with 1.6 to 2.0 percent sulfur coal being fired in the boilers. Among minor problems that were encountered and corrected were difficulties with the pH sensors and sulfur dioxide analyzers and plugging of spray nozzles.

OPERATION HISTORY

Tables 3, 4, and 5 summarize the performance of the FGD system from prestart-up operation through November 1977. Start-up and early operation of the system were conducted mostly at 50 percent load capacity because of major repair work on both turbine generators and because of a possible lime shortage during renegotiation of a supply contract. The system was operated in an open water-loop mode to gain operational experience while supplying the settling pond with water for recirculation to the process.

A 6-month qualification program was conducted in 1976 by the system supplier. The purpose of this program was to verify process design in operation with closed water loop and full boiler load. Performance of the system from September 1975 to November 1977 is summarized below:

1975 Operation: Initial operation on September 13, 1975, was followed by shakedown and debugging. Many of the system outages occurred because of scheduled inspections and minor design adjustments. Total service time for the FGD system in 1975 was 649.20 hours.

1976 Operation: The FGD system was available for service 7502.88 hours and operated 6045.94 hours. The boilers were in service 6969.82 hours; annual average unit load factor was 47.5 percent.

Table 3. GREEN RIVER FGD SYSTEM: 1975 OPERATIONAL DATA

MONTH	Hours in period	Hours FGD system available	Hours FGD called upon	Hours FGD system operated	Hours boilers operated	Unit load factor,%	FGD system performance factors, %			
							Avail-ability	Oper-ability	Relia-bility	Utiliza-tion
July	744		Mechanical and electrical testing; air and water tests							
Aug.	744		Mechanical reliability Tests							
Sept.	720			139.17						
Oct.	744			149.53						
Nov.	720			146.00						
Dec.	744			412.50						
Total	4416			649.20						

Table 4. GREEN RIVER FGD SYSTEM: 1976 OPERATIONAL DATA

MONTH	Hours in period	Hours FGD system available	Hours FGD called upon	Hours FGD system operated	Hours boilers operated	Unit load factor,%	FGD system performance factors, %			
							Avail-ability	Oper-ability	Relia-bility	Utiliza-tion
Jan.	744	312.00	456.00	64.00	571.55	55.2	41.9	11.2	14.0	8.6
Feb.	696	486.17	499.38	210.75	499.38	40.7	69.9	42.2	42.2	30.3
Mar.	744	721.72	408.66	386.38	457.53	43.7	97.0	84.4	94.5	51.9
Apr.	720	648.00	552.00	552.00	552.00	50.2	90.0	100.0	100.0	76.7
May	744	606.18	455.88	455.88	455.88	44.1	81.4	100.0	100.0	61.2
June	720	720.00	596.43	588.85	596.43	62.3	100.0	98.7	98.7	62.3
July	744	665.85	583.53	574.43	583.53	51.2	89.5	98.4	98.4	77.2
Aug.	744	722.45	744.00	722.45	744.00	54.0	97.1	97.1	97.1	97.1
Sept.	720	617.20	571.20	571.20	571.20	32.5	85.7	100.0	100.0	79.3
Oct.	744	744.00	698.55	698.55	698.55	37.7	100.0	100.0	100.0	93.9
Nov.	720	720.00	704.25	704.25	704.25	51.4	100.0	100.0	100.0	97.8
Dec.	744	539.31	591.48	517.20	535.52	46.5	72.5	87.4	96.6	69.5
Total	8784	7502.88	6861.36	6045.94	6969.82	47.5	85.4	86.7	88.1	68.8

Table 5. GREEN RIVER FGD SYSTEM: 1977 OPERATIONAL DATA (THROUGH NOVEMBER)

MONTH	Hours in period	Hours FGD system available	Hours FGD called upon	Hours FGD system operated	Hours boilers operated	Unit load factor,%	FGD system performance factors, %			
							Avail-ability	Oper-ability	Relia-bility	Utiliza-tion
Jan.	744	698.29	744.00	698.26	744.00	56.5	93.9	93.9	93.9	93.9
Feb.	672	242.80	266.12	242.80	266.12	32.8	36.1	91.2	91.2	36.1
Mar.	744	0	0	0	0	0	0	0	0	0
Apr.	720	288.00	166.82	164.00	166.82	9.4	40.0	98.3	98.3	22.8
May	744	735.65	526.55	513.27	526.55	34.4	98.9	97.5	97.5	69.0
June	720	720.00	34.38	34.38	34.38	1.3	100.0	100.0	100.0	4.8
July	744	744.00	0	0	0	0	100.0	0	0	0
Aug.	744	744.00	0	0	0	0	100.0	0	0	0
Sept.	720	720.00	0	0	0	0	100.0	0	0	0
Oct.	744	744.00	0	0	0	0	100.0	0	0	0
Nov.	720	634.20	331.90	300.85	331.90	32.8	88.1	90.6	90.6	41.8
Total	8016	6294.93	2069.77	1953.56	2069.77	15.2	78.5	94.4	94.4	24.4

Based upon these values, the values for system availability, operability,* reliability,† and utilization‡ in 1976 are 85.4, 86.7, 88.1, and 68.8 percent, respectively.

1977 Operation: Service times for the boiler and scrubber dropped off sharply from 1976 levels, largely because of a plant operator strike from June to October 1977. In addition, the units and scrubber were shut down in February and March for scrubber stack and boiler repairs. Through November the FGD system was available 6294.93 hours and operated 1953.56 hours. The boilers were in service 2069.77 hours; annual average unit load factor was 15.2 percent. Based on these values, the values for system availability, operability, reliability, and utilization in the 11-month period are 78.5, 94.4, 99.4, and 24.4 percent, respectively.

START-UP AND OPERATION: PROBLEMS AND SOLUTIONS

Start-up and operation of the Green River scrubbing system have been accompanied by various problems, for many of which both the utility operators and the FGD system supplier have conceived and implemented solutions. Table 6 summarizes the problems encountered and the measures taken to correct them. The major problems and solutions are discussed briefly below.

Problems Related to System Chemistry

Plugging occurred in the spray nozzles and mobile bed, and scale formed in and downstream of the mist eliminator. Hard gypsum scale developed in the lower section of the mobile-bed

---

* Operability index: the number of hours the FGD system is operational divided by the boiler operating hours, expressed as a percentage.

† Reliability index: the number of hours the FGD system is operational divided by the number of hours the FGD system is called upon to operate, expressed as a percentage.

‡ Utilization index: the number of hours the FGD system is operational divided by the number of hours in the period, expressed as a percentage.

Table 6. SUMMARY OF PROBLEMS AND SOLUTIONS, GREEN RIVER FGD SYSTEM

Period	Problem	Solution
Aug. 75	Oscillation of scrubber stack when booster fan was put in service.	Installed strengthening vanes to dampen the standing wave frequency.
Sept. 75	Plugging of spray nozzles.	Cleaned nozzles.
Oct. 75	Plugging of recycle tank screens and spray nozzles.	Cleaned components.
Nov. 75	Plugging of recycle tank screens.	Cleaned screens.
Dec. 75		
Jan. 76	Numerous frozen and/or ruptured lines.	Thawed lines. Repaired or replaced damaged lines.
	Inoperable recycle pumps, sump pumps, and feed tank agitator.	Repaired components.
Feb. 76	Failure of recycle pumps, reactant feed pumps, and tank agitators.	Repaired components. Cleaned all related components (tanks, pipes, pumps).
Mar. 76	Failure of rubber-lined recycle pump impellers.	Changed all rubber-lined impellers from two-piece to one-piece construction.
Apr. 76		
May 76	Minor failures of stack liner (Carboline).	
June 76	Scale in scrubber.	Shut scrubber down; removed scale.
July 76		
Aug. 76	Excessive vibration of scrubber booster fan.	Shut scrubber down; repaired fan.

Table 6 (Continued).

Period	Problem	Solution
Sept. 76	Continuation of minor fan problems	Shut scrubber down; repaired fan.
Oct. 76		
Nov. 76	Scrubber system checkout	Replaced some mobile-bed contactor spheres.
Dec. 76		
Jan. 77		
Feb. 77	Corrosion and erosion of Carboline stack lining and shell.	Repaired stack shell with welded backup plates. Replaced Carboline liner with Precrete G-8 applied to wire mesh.
Apr. 77		
May 77		
June 77	Malfunction of underbed damper.	Repaired component.
July 77	No operation - plant operator strike	
Aug. 77	No operation - plant operator strike	
Sept. 77	No operation - plant operator strike	
Oct. 77	No operation - plant operator strike	
Nov. 77		

contactor during initial operation, probably because calcium sulfite tends to precipitate as the pH of the scrubbing solution reaches 9.0 to 10.0. Then, in the presence of high oxygen concentrations in the flue gas, the sulfite is oxidized to sulfate, resulting in the scale formation. To solve this problem the oxygen content of the flue gas was reduced by minimizing air leakage into the system and the pH sensors were modified and relocated so as to reduce pH levels of the solution.

Recent system modifications designed to reduce plugging and scaling are cycling the mobile-bed dampers to prevent stagnation zones and removal of the spray nozzles to increase liquid flow to the unit and prevent settling out of solids in the piping.

Mechanical Problems

Mechanical malfunctions and failures have been minimal and associated mainly with the pumps, fans, and dampers. The original slurry recirculation pumps were rubber-lined and rubber-covered impeller units. The rubber repeatedly peeled from the impellers, and the lining was destroyed after minimal service time. Although the impeller design was changed from a two-piece to a one-piece construction, continuing failures prompted KU to switch to Ni-hard impellers. Vibrations associated with the scrubber booster fan have caused occasional shutdowns for rebalancing. The guillotine gas bypass dampers (three; two located near the existing stack and one for the scrubber) are difficult to close in cold weather and must be operated manually.

Problems Related to System Design

The most severe problems to date concern the high loadings of acid mist in the scrubber exit gas stream. These high loadings have caused acid condensation and rainout in the stack and in the immediate plant area. The stack liner and shell have failed, and acid rainout damaged automobiles and the superstructure of a substation on the plant grounds. To rectify this situation KU and AAF have implemented or are engineering the following modifications.

- The Carboline stack lining, which failed around nearly half of the circumference, has been replaced with a 1.9-cm (3/4-in.) refractory coating (Precrete G-8) applied over a wire mesh.
- The stack shell was repaired by welding a backup metal plate to the portions of the stack that were pitted. Half of the stack was covered over its entire height with a 9.5-mm (3/8-in.) steel plate.
- The radial-vane mist eliminator is being modified to reduce formation of acid mist and fouling. If this is not effective, the unit will be replaced with a chevron-type mist eliminator.
- An indirect, hot-air, stack gas reheat system will be incorporated to raise gas temperature by 10°C (50°F). Extraction steam from another unit will supply heat to ambient air, which will be injected into the scrubbing system before gases exit through the scrubber stack.

ECONOMICS

Tables 7 and 8 summarize the total installed capital cost and the annual operating and maintenance costs associated with the Green River scrubbing system. The total installed capital cost of the system is $3,444,000, which equals $57.4/kW based upon the system's net generating capacity of 60 MW. This figure, in 1976 dollars, includes the particulate removal equipment associated with the scrubbing system. Excluded are the system design modifications by KU and AAF. The total annual operating and maintenance costs are $504,057, which equals 2.019 mills/kWh based upon the 1976 unit capacity factor of 47.5 percent. Excluded is the electrical energy cost, which is 10.04 mills/kWh based upon a system power demand of 1500 kW.

SYSTEM PERFORMANCE: SO_2 REMOVAL EFFICIENCY

Efficiency of the system in removing sulfur dioxide and particulate from flue gases has not been reliably determined.

Table 7. GREEN RIVER SCRUBBING SYSTEM:

TOTAL INSTALLED CAPITAL COSTS[a]

Item	$/kW	Dollars[b]
Scrubber equipment[c]	48.3	2,898,000
Ancillary equipment[d]	3.1	186,000
Sludge disposal, sludge transportation, and site preparation	6.0	360,000
Total	57.4	3,444,000

[a] Based upon a net generating capacity of 60 MW.

[b] 1976 dollars.

[c] Equipment furnished by AAF, excluding sludge disposal.

[d] Equipment not furnished by AAF, excluding sludge disposal.

Table 8. GREEN RIVER SCRUBBING SYSTEM:
ANNUAL OPERATING, MAINTENANCE AND UTILITIES COST[a]

Item	mills/kWh	Dollar[b]
Operating:		
Materials[c]	1.206	301,090
Labor	0.188	46,936
Total operating	1.394	348,026
Maintenance:		
Materials	0.195	48,684
Labor	0.181	45,188
Total maintenance	0.376	93,872
Utilities	0.249	62,165
Total	2.019[d]	504,057

[a] Based upon a unit capacity factor of 47.5 percent.
[b] 1976 dollars.
[c] Reagent and chemicals.
[d] Does not include electrical energy cost, 10.04 mills/kWh.

Continuous monitoring data recorded by AAF during the initial operating phase show sulfur dioxide removal efficiency well above the design guarantee value, at about 90 percent. An attempted efficiency test in December 1976 failed because air leakage in the boiler prevented operation at full capacity. Another efficiency test is tentatively scheduled for February 1978.

APPENDIX A

PLANT SURVEY FORM

A. Company and Plant Information

1. Company name: Kentucky Utilities
2. Main office: Lexington, Kentucky
3. Plant name: Green River Power Station
4. Plant location: Central City, Kentucky
5. Responsible officer: Joseph Beard
6. Plant manager: J.W. Reisinger
7. Plant contact: J.W. Reisinger/S.V. Anderson
8. Position: Plant Superintendent/Assistant Superintendent
9. Telephone number: (502) 754-4828
10. Date information gathered: March 4 and June 30, 1976

Participants in meeting	Affiliation
J.W. Reisinger	Kentucky Utilities
S.V. Anderson	Kentucky Utilities
Frank Palameri	American Air Filter
James Martin	American Air Filter
G.A. Isaacs	PEDCo Environmental
B.A. Laseke	PEDCo Environmental
R.I. Smolin	PEDCo Environmental
T.C. Ponder	PEDCo Environmental
R. Klier	PEDCo Environmental

B. Plant and Site Data

1. UTM coordinates: ______

2. Sea Level elevation: The plant power building is approximately 122 m (400 ft) above sea level.

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

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

5. General description of plant environs: Sparsely populated, wooded, hilly area--approximately 8 km (5 mi.) north of Central City, Kentucky.

6. Coal shipment mode: High-sulfur coal is shipped in by barge on Green River. Low-sulfur coal is shipped to the plant by truck and rail.

C. FGD Vendor/Designer Background

1. Process name: Wet lime scrubbing

2. Developer/licensor name: American Air Filter

3. Address: 215 Central Avenue, Louisville, Kentucky

4. Company offering process:

Company name: American Air Filter

Address: 215 Central Avenue

Location: Louisville, Kentucky

Company contact: A.H. Berst

Position: SO_2 Scrubber Project Engineering

Telephone number: (502) 637-0534

5. Architectural/engineers name: American Air Filter

Address: 215 Central Avenue

Location: Louisville, Kentucky

Company contact: A.H. Berst

Position: SO_2 Scrubber Projects Engineering

Telephone number: (502) 637-0534

D. Boiler Data

1. Boiler: Nos. 1, 2, and 3
2. Boiler manufacturer: Babcock and Wilcox
3. Boiler service (base, standby, floating, peak):

   Peak load service

4. Year boiler placed in service: 1949, 1950 and 1951
5. Total hours operation:
6. Remaining life of unit: No plans to retire unit
7. Boiler type: Dry bottom, pulverized coal units
8. Served by stack no.: Main stack and scrubber stack
9. Stack height: 23.77 m. (78 ft) (scrubber)
10. Stack top inner diameter: 4.88 m. (16 ft)
11. Unit ratings (MW): 37.5/turbine (2 turbines total)

    Gross unit rating: 32/turbine (2 turbines total)

    Net unit rating without FGD: 30.5/turbine (2 turbines total)

Net unit rating with FGD: 29.5/turbine (2 turbines total)

Name plate rating: 37.5/turbine (2 turbines total)

12. Unit heat rate: 13,978 kJ/net kWh (13,250 Btu/net kWh)

    Heat rate without FGD: ________

    Heat rate with FGD: ________

13. Boiler capacity factor, (1976): 47.5%

14. Fuel type (coal or oil): Coal

15. Flue gas flow: 169 m^3/sec (360,000 acfm)

    Maximum: 169 m^3/sec (360,000 acfm)

    Temperature: 149°C (300°F)

16. Total excess air: 25%

17. Boiler efficiency: 80%

E. Coal Data

1. Coal supplier:

   Name: P and M Coal Co. and River Processing Co.

   Location: Muhlenberg County, Kentucky and Hazard, Harlan County, Kentucky

   Mine location: Drake Mine and Hoyt Mine

   County, State: Muhlenberg, Kentucky, and Harlan, Ky.

   Seam: ________

2. Gross heating value: 25 MJ/kg (10,800 Btu/lb) (high-sulfur coal)

3. Ash (dry basis): 13.44% (high-sulfur coal)

4. Sulfur (dry basis): 4.0% (high-sulfur coal); 1.0% low-sulfur coal)

5. Total moisture: 12.1% (high-sulfur coal)

6. Chloride: Mineral analysis not available

7. Ash composition (See Table A1)

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	Ash Analysis Not Available
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: 42 ng/J (0.097 lb/10^6 Btu)

      AQCR priority classification: II

      Regulation and section No.: Ky/401 KAR 3:060

   b) Future requirement (Date:): ________

      Regulation and section No.: ________

2. Applicable SO_2 emission regulation

   a) Current requirement: 720 ng/J (1.67 lb/10^6 Btu)

      AQCR Priority Classification: II

      Regulation and section No.: Ky/401 KAR 3:060

   b) Future requirement (Date:) ________

Regulation and section No.: ____________________

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

1. Trade name: 1.9 cm (3/4 in.) pebble lime

   Principal ingredient: Calcium oxide

   Function: Sulfur dioxide absorbent

   Source/manufacturer: Mississippi Lime Co./Alton, Illinois

   Quantity employed: 0.5 kg/sec (2 ton/hr)

   Point of addition: Dry storage bin into slaker

2. Trade name: 1.9 cm (3/4 in.) pebble lime

   Principal ingredient: Calcium oxide

   Function: Sulfur dioxide absorbent

   Source/manufacturer: National Gypsum Co.

   Quantity employed: 0.5 kg/sec (2 ton/hr)

   Point of addition: Dry storage bin into slaker

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: Not applicable

Manufacturer: ______

Particulate removal efficiency: ______

Outlet temperature: ______

Pressure drop: ______

2. Mechanical collector(s)

Number: ______

Type: Multicyclones

Size: 49 m^3/sec (105,000 cfm); 23-cm (9-in.) diameter

Manufacturer: Western Precipitator

Particulate removal efficiency: 85 percent (design)

Pressure drop: 498 Pa (2 in. H_2O)

3. Particulate scrubber(s)

Number: One

Type: Variable-throat venturi scrubber

Manufacturer: American Air Filter

Dimensions: Propietary

Material, shell: Mild steel (stainless steel throat)

Material, shell lining: Acid brick and precrete

Material, internals: None

No. of modules: One

No. of stages: One

Nozzle type: Spinner vane (original equipment)

Nozzle size: ________

No. of nozzles: ________

Boiler load: 100% (Units 1, 2, and 3)

Scrubber gas flow: 135 m^3/sec at 52°C (228,300 acfm at 126°F)

Liquid recirculation rate: 83 l/sec (1360 gpm)

Modulation: None

L/G ratio: 7.65 l/Nm^3 (34.5 gal/1000 acf)

Scrubber pressure drop: 1743 Pa (7 in. H_2O)

Modulation: Plug (limitorque operator)

Superficial gas velocity: ________

Particulate removal efficiency: Not yet determined

Inlet loading: 5038 mg/m^3 (2.2 gr/dscf)

Outlet loading: ________

SO_2 removal efficiency:

Inlet concentration: 2200 ppm (109 lb/min)

Outlet concentration: Not available

4. SO_2 absorber(s)

Number: One

Type: Mobile-bed contactor

Manufacturer: American Air Filter

Dimensions: 6.1 x 6.1 x 8.4 m (20 x 20 x 27.5 ft)

Material, shell: Mild steel

Material, shell lining: 1.9-cm (3/4-in.) acid-proof lining

Material, internals: Mobile bed (solid sphere packing)

No. of modules: One

No. of stages: Compartments in mobile bed

Packing type: PVC spheres

Packing thickness/stage: Propietary

Nozzle type: Propietary

Nozzle size: Propietary

No. of nozzles: Propietary

Boiler load: 100%

Absorber gas flow: 135 m^3/sec at 52°C (288,200 acfm at 126°F)

Liquid recirculation rate: 595 l/sec (9750 gpm)

Modulation: None

L/G ratio: 4.4 l/m^3 (34 gal/1000 acf)

Absorber pressure drop: 996 Pa (4 in. H_2O)

Modulation: None

Superficial gas velocity: 4 m/sec (14 ft/sec)

Particulate removal efficiency: (overall) 99%

Inlet loading:

Outlet loading: 102 mg/m^3 (0.044 gr/dscf)

SO_2 removal efficiency: 80% guarantee

Inlet concentration: 2200 ppm (to venturi)

Outlet concentration: 400 ppm (from absorber)

5. Clear water tray(s)

Number: Not applicable

Type: ______

Materials of construction: ______

L/G ratio: ______

Source of water: ______

6. Mist eliminator(s)

Number: One

Type: Radial vane

Materials of construction: Stainless steel

Manufacturer: American Air Filter

Configuration (horizontal/vertical): Horizontal

Distance between scrubber bed and mist eliminator: Propietary

Mist eliminator depth: Propietary

Vane spacing: Propietary

Vane angles: Propietary

Type and location of wash system: Outward spray at 3 l/sec (50 gpm)

Superficial gas velocity: 7.5 m/sec (25 ft/sec)

Pressure drop: 498 Pa (2 in. H_2O)

Comments: Radial vane unit may be replaced by a chevron-type unit if modifications do not improve efficiency.

7. Reheater(s): None - not applicable

Type (check appropriate category): ______

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

Gas conditions for reheat:

Flow rate: ____________________

Temperature: ____________________

SO_2 concentration: ____________________

Heating medium: ____________________

Combustion fuel: ____________________

Percent of gas bypassed for reheat: ____________________

Temperature boost (ΔT): ____________________

Energy required: ____________________

Comments: KU and AAF are planning to install a hot air injection reheat system using extraction steam from an adjacent unit.

8. Fan(s) One, forced-draft FGD booster fan

Type: Dual inlet type; 46 cm (18 in. H_2O) static pressure

Materials of construction: Mild steel

Manufacturer: Buffalo Forge/Allis Chalmer

Location: Upstream of FGD system

Fan/motor speed: 890 rpm - direct drive

Motor/brake power: 1120 W (1500 hp)

Variable speed drive: None - damper control

9. Tank(s) One common recirculation tank

Materials of construction: Acid-proof concrete

Function: Reactant tank for scrubbing solution

Configuration/dimensions: Rectangular - 3 compartments

Capacity: 1180 kl (311,040 gal.)

Retention times: 7 minutes/compartment; 21 minutes total

Covered (yes/no): No

Agitator description: 1 agitator per compartment

10. Recirculation/slurry pump(s)

11 PUMPS FOR THE SCRUBBING SYSTEM IN TOTAL

Number	Description	Size	Manufacturer	Materials	Comments
3	Absorber recycle	5900 gpm	Ingersoll-Rand	Rubber-lined	2 oper. 1 spare 115' head
2	Bleed stream	350 gpm	Ingersoll-Rand	Rubber-lined	Continuous maximum
2	Reactant	90 gpm	Ingersoll-Rang	Rubber-lined	
2	Pond return		Ingersoll-Rand	Rubber-lined	
2	Sump pumps	50 gpm	Ingersoll-Rand	Rubber-lined	

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: Not applicable

Description:

Area:

Depth:

Liner type:

Location:

Typical operating schedule:

Ground water/surface water monitors:

15. Final disposal site(s)

Number: One

Description: Blowdown pond; clay lined-impervious

Area: Maximum capacity is 511,000 m^3 (414 acre-ft), suf-

Depth: ficient for 20 years of use

Location: On plant site - 0.8 km (0.5 mile) from scrubber

Transportation mode: 13-cm (5-in.) diameter piping

Typical operating schedule: Continuous feed while scrubber is in operation

16. Raw materials production

Type: Not applicable

Number:

Manufacturer:

Capacity: 0.5 kg/sec (2 ton/hr) lime

Product characteristics: Pebble lime (1.9 cm, 0.75 in.) is slaked to 20% solids content slurry.

I. Equipment Operation, Maintenance, and Overhaul Schedule

1. Scrubber(s)

Design life:

Elapsed operation time: 8649 hours through Nov. 1977

Cleanout method: Water flushing

Cleanout frequency: During reliability run 4 or 5 times in 6 months

Cleanout duration:

Other preventive maintenance procedures: The unit is down on weekends; no demand.

2. Absorber(s)

Design life: ____

Elapsed operation time: 8649 hours through Nov. 1977

Cleanout method: Water flushing

Cleanout frequency: Same as above

Cleanout duration: ____

Other preventive maintenance procedures: See above

3. Reheater(s)

Design life: Not applicable

Elapsed operation time: ____

Cleanout method: ____

Cleanout frequency: ____

Cleanout duration: ____

Other preventive maintenance procedures: ____

4. Scrubber fan(s)

Design life: ____

Elapsed operation time: 8649 hours through Nov. 1977

Cleanout method: ____

Cleanout frequency: As needed

Cleanout duration: ____

Other preventive maintenance procedures: See above

5. Mist eliminator(s)

Design life: ____

Elapsed operation time: 8649 hours through Nov. 1977

Cleanout method: ______

Cleanout frequency: As needed

Cleanout duration: ______

Other preventive maintenance procedures: Problems may necessitate design change to chevron type

6. Pump(s)

Design life: ______

Elapsed operation time: 8649 hours through Nov. 1977

Cleanout method: ______

Cleanout frequency: As needed

Cleanout duration: ______

Other preventive maintenance procedures: See above

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

Design life: Not applicable

Elapsed operation time: ______

Cleanout method: ______

Cleanout frequency: ______

Cleanout duration: ______

Other preventive maintenance procedures: ______

8. Sludge disposal pond(s)

Design life: 9 years expandable to 20 years

Elapsed operation time: 8649 hours through Nov. 1977

Capacity consumed: ______

Remaining capacity: ______

Cleanout procedures: ______

J. Cost Data

1. Total installed capital cost: $3.444 million
2. Annualized operating cost: 2.019 mills/kWh
3. Cost analysis (see breakdown: Table A2)
4. Unit costs
   a. Electricity: 0.249 mills/kWh (utilities)
   b. Water: 0.249 mills/kWh (utilities)
   c. Steam: Not applicable
   d. Fuel (reheating/FGD process): Not applicable
   e. Fixation cost: Not applicable
   f. Raw material: 1.206 mills/kWh (lime)
   g. Labor: 1.401 mills/kWh (operating and maintenance labor)
5. Comments The unit costs figures are the operating cost figures supplied by the utility for that particular category for 1976 operation. The electrical energy cost penalty, 10.04 mills/kWh, is excluded. The cost of steam may be added because of the planned installation of a steam/hot air reheat system.

Table A2 Cost Breakdown

Cost elements	Included in cost estimate: Yes	Included in cost estimate: No	Estimated amount or % of total capital cost
A. Capital Costs			
Scrubber modules	X		$2.898 million (1976)
Reagent separation facilities		X	Not applicable
Waste treatment and disposal pond		X	
Byproduct handling and storage			
Site improvements		X	$360,000 (1976)
Land, roads, tracks, substation		X	
Engineering costs	X		
Contractors fee	X		
Interest on capital during construction		X	$186,000 (1976)
B. Annualized Operating Cost			
Fixed Costs			
Interest on capital		X	
Depreciation		X	
Insurance and taxes		X	
Labor cost including overhead		X	
Variable costs			
Raw material	X		$301,090 (1976)
Utilities	X		$ 62,165 (1976)
Maintenance (labor)	X		$ 92,124 (1976)

K. Instrumentation

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

- Reagent addition: pH control, monitored in the second compartment of the reactant tank
- Liquor solids content: Nuclear density meter, situated in scrubber recycle line.
- Liquor dissolved solids content: ______
- Liquor ion concentrations

  Chloride: Not applicable

  Calcium: ______

  Magnesium: Not applicable

  Sodium: ______

  Sulfite: Not applicable

  Sulfate: Not applicable

  Carbonate: ______

  Other (specify): Not applicable

- Liquor alkalinity: ______

- Liquor pH: pH meters/2 each per reactant tank compartment

- Liquor flow: Not control

- Pollutant (SO_2, particulate, NO_x) concentration in flue gas: SO_2 analyzers are installed upstream and downstream of scrubber

- Gas flow: Dampers in SO_2 absorber section are closed/ opened as a function of load variations.

- 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: See Section 3, Process Control, and Figure 2, on pages 11 to 14 in the text of the report for specific information on the Green River FGD control system.

L. Discussion of Major Problem Areas:

1. Corrosion:

   Scrubber stack - Corrosion of original carboline liner; replaced with Precrete G-8 and wire mesh.

2. Erosion:

Scrubber stack - Carboline lining has been peeling. Relined the stack in the problem spots. Replaced with Precrete G-8 over wire mesh.

3. Scaling:

Scrubber internals - The bottom sections of the mobile-bed contactor have become coated with gypsum scale because of high pH of the scrubbing solution (pH above 8.5).

4. Plugging:

Mist eliminator and nozzles - Frequent plugging causes a decrease of flow and an increase in pressure, requiring system shutdown and manual cleaning. May replace with chevron unit.

5. Design problems:

6. Waste water/solids disposal:

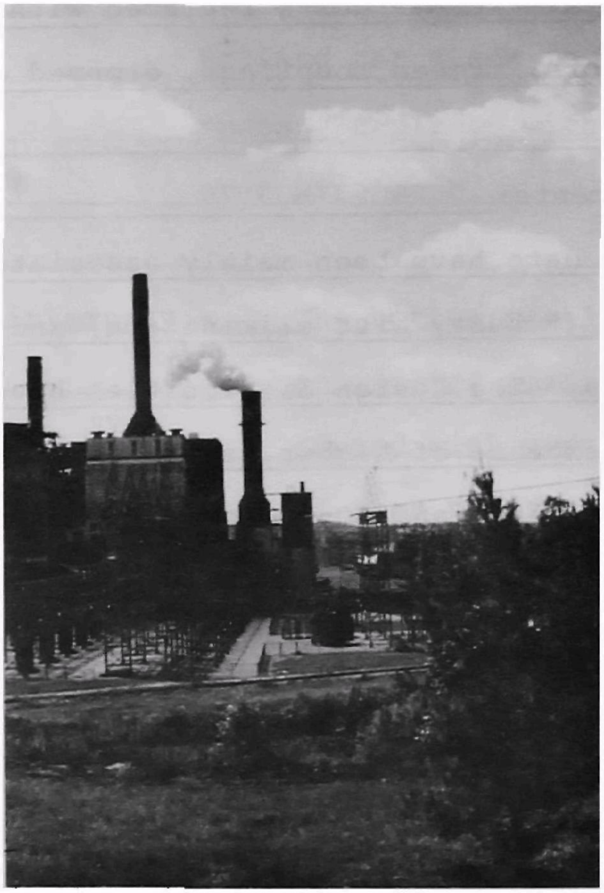
7. Mechanical problems: Some minor initial sphere losses in mobile-bed; replaced with larger spheres. Recycle pumps, all rubber units replaced with Ni-hard. Agitators, broken couplings, dropped one agitator.

M. General comments:

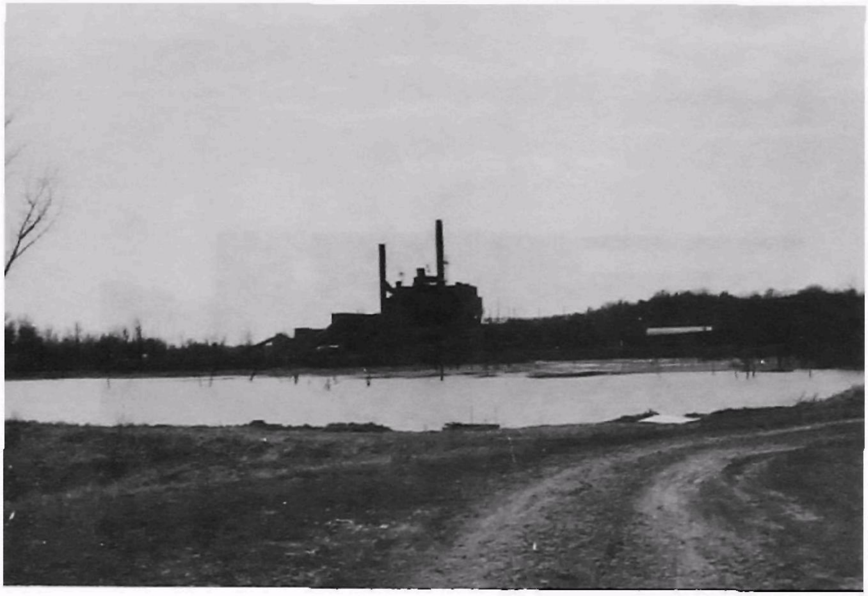
Problems to date have been mainly associated with FGD design limitations (reheat, mist elimination) and minor mechanical difficulties. The design difficulties have been resolved, but at the expense of higher capital and operating costs. Actual particulate and SO_2 removal efficiencies have not yet been accurately measured (test scheduled for the first quarter of 1978). To date, the system has exhibited high availability index values.

APPENDIX B

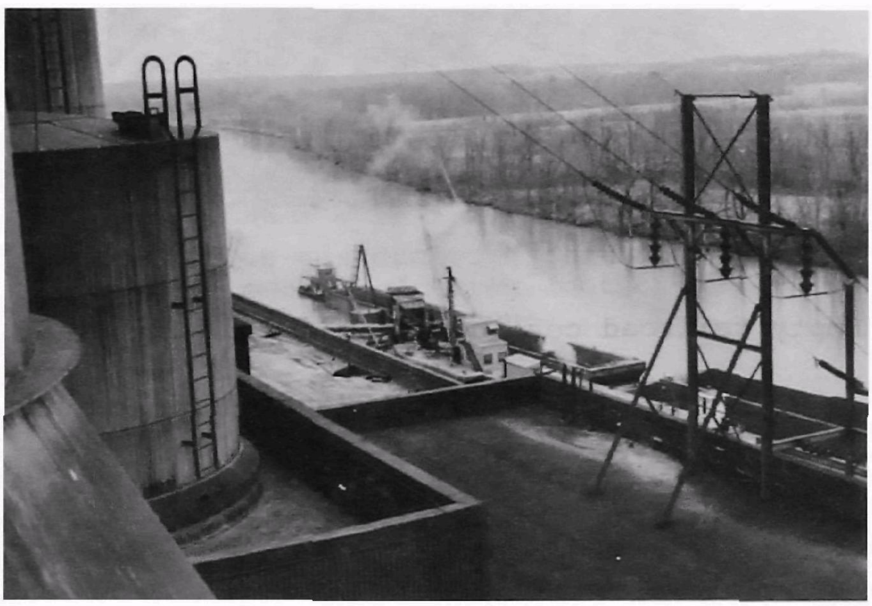
PLANT PHOTOGRAPHS



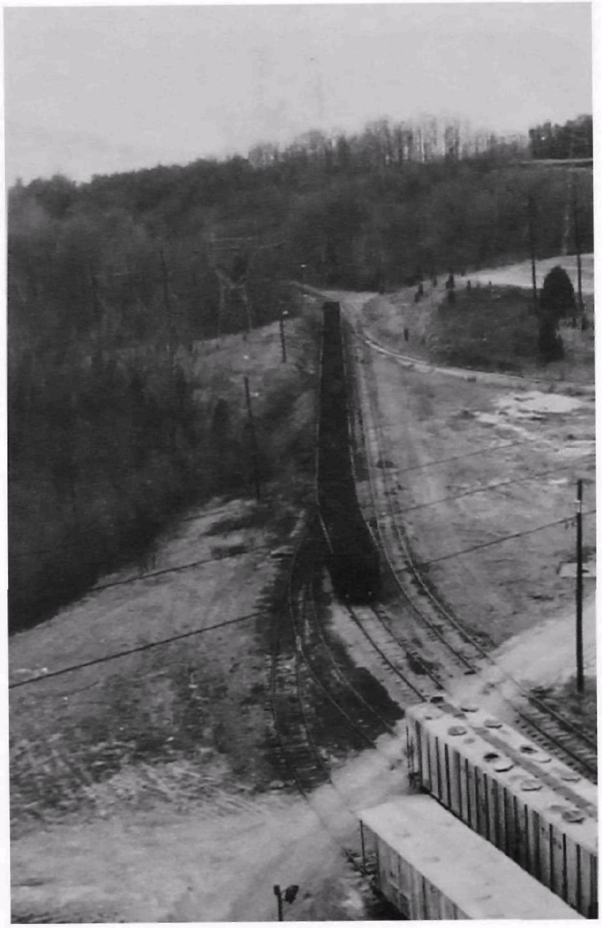
1. Front view of the Green River Power Station. The scrubbing module, stack, and lime slurry preparation area appear in the center of the photograph to the right of the main boiler house.



2. Side view of the Green River Power Station, as seen from the waste disposal area.

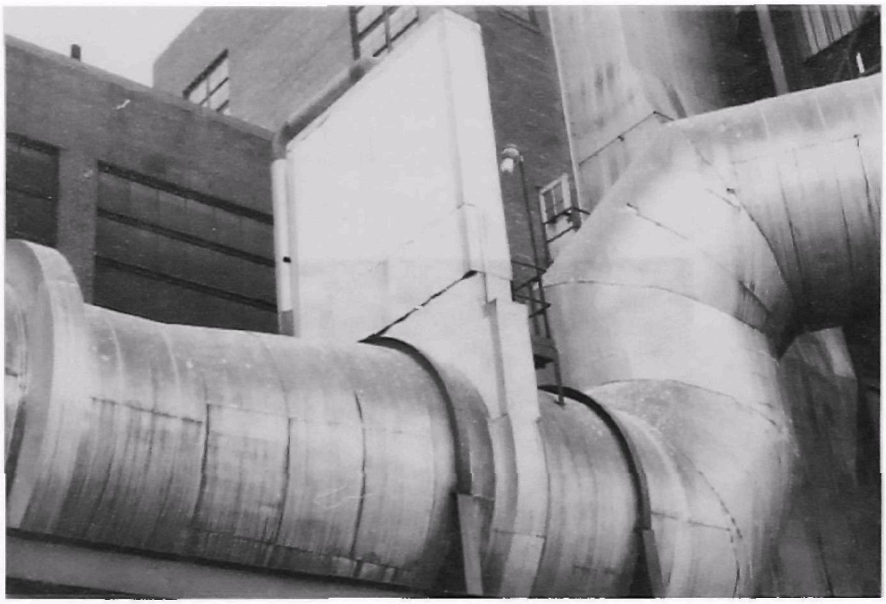


3. Coal barges and unloading area for the Green River Power Station, as seen from the top of the scrubber module.

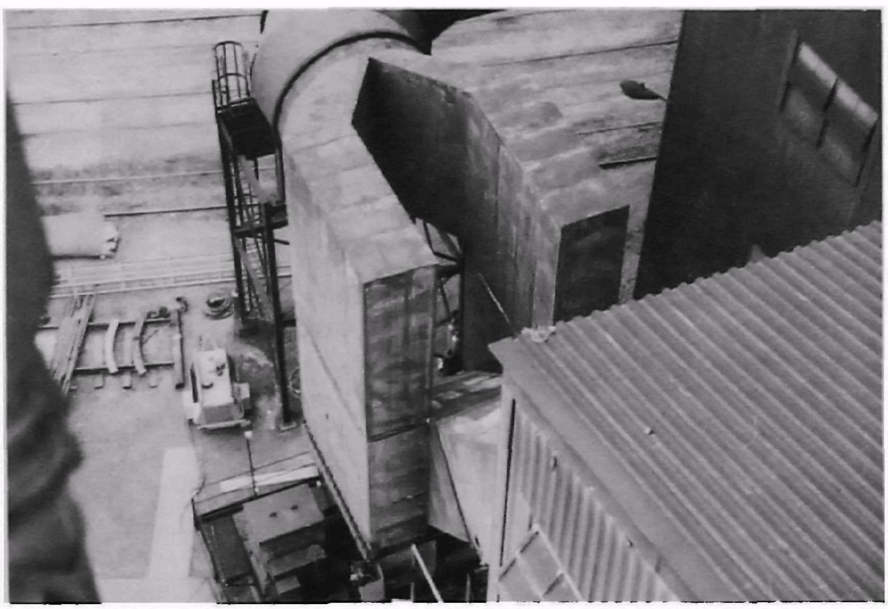


4. Empty railroad coal cars located on the plant grounds.

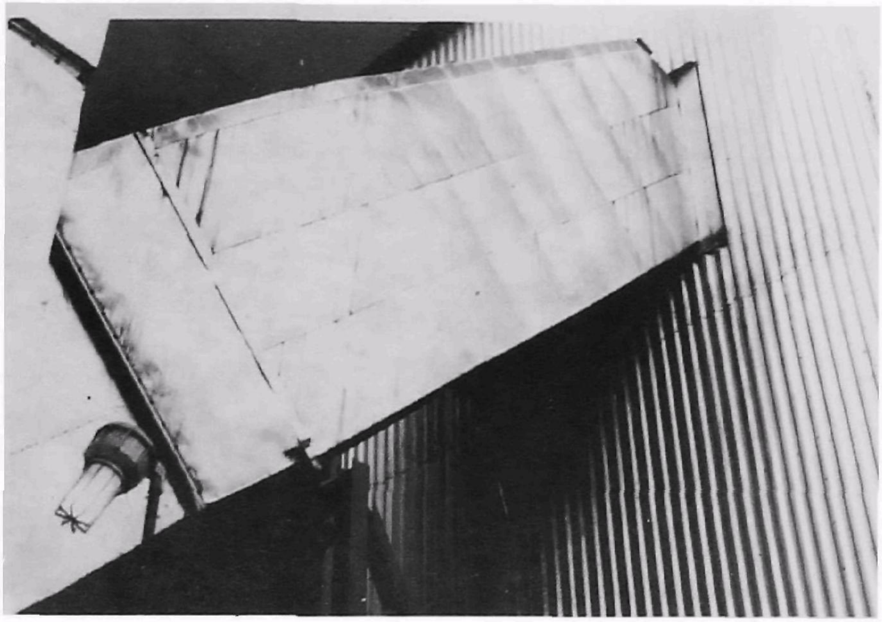
5. Boiler flue gas ductwork that directs gas to the scrubber module situated (out of view) around the corner of the boiler house.



6. Guillotine gas bypass damper in the boiler flue gas duct leading to the scrubber.

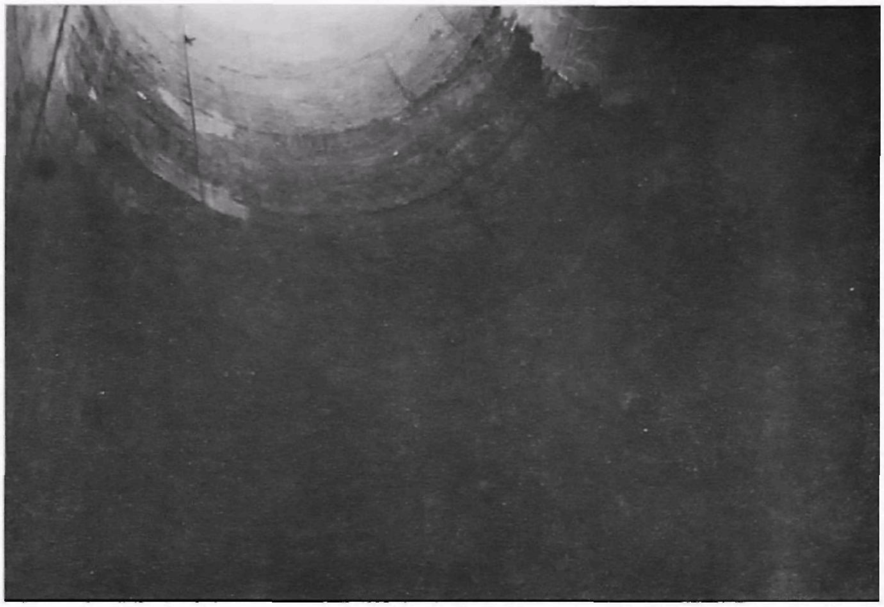


7. Top view of the dual-inlet scrubber booster fan located upstream of the breeching leading into the scrubber house.



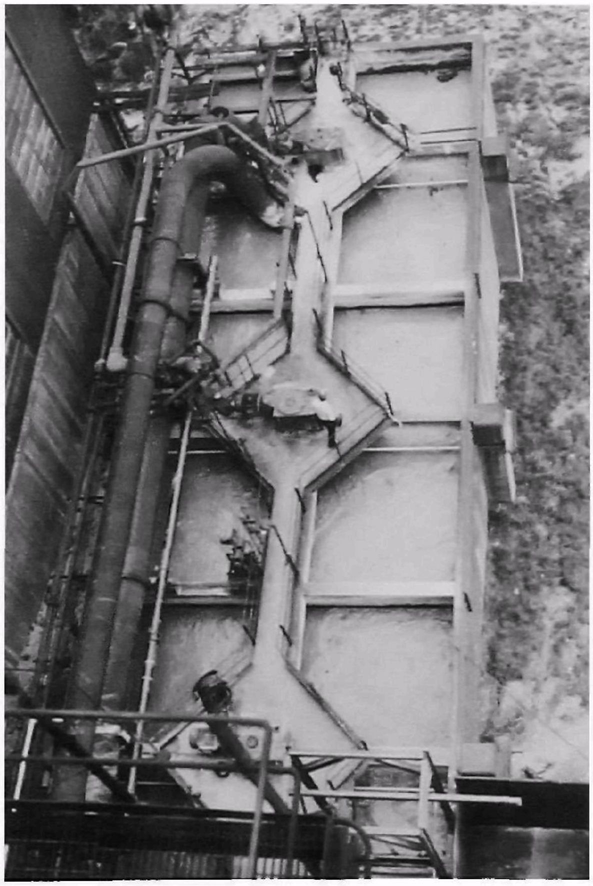
8. Side view of the breeching between the scrubber booster fan and scrubber house.

9. Upward view of the interior of the scrubber stack during a shutdown. Repairs to the corrosion-damaged liner and stack shell are in progress.

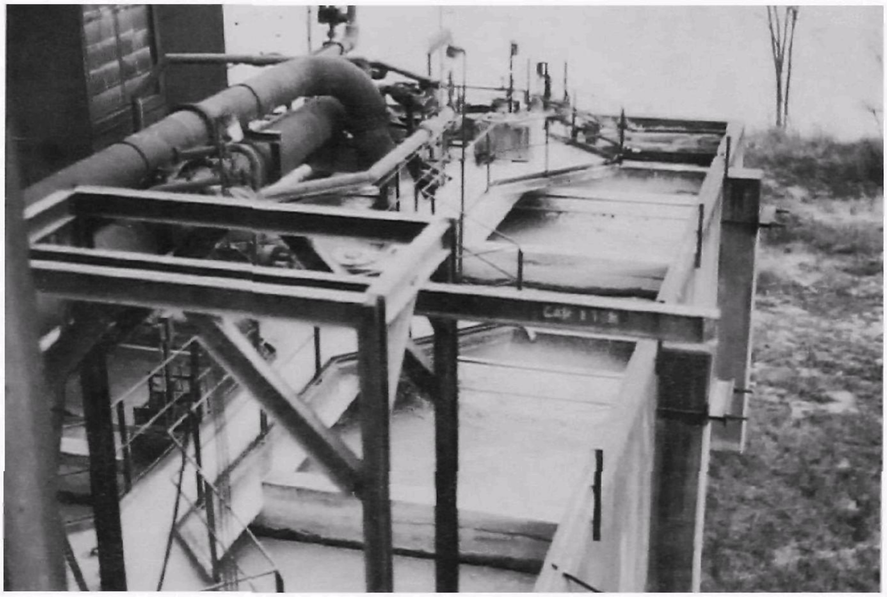


10. Close-up view of the corrosion-damaged area in the scrubber stack.

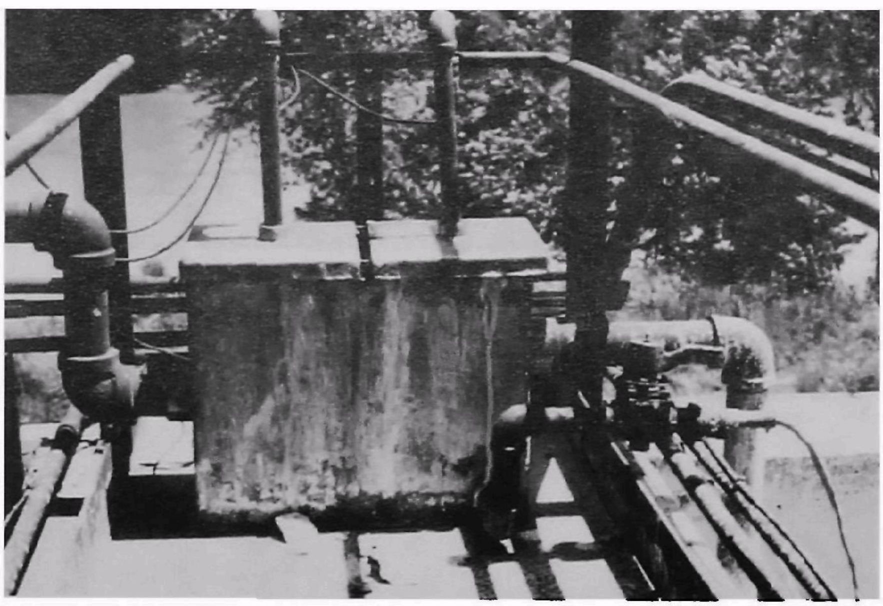
11. Close-up view of the lime slurry feed preparation tank located beneath the lime storage silo.



12. Top view of the compartmentalized recycle tank located beneath the scrubber module.



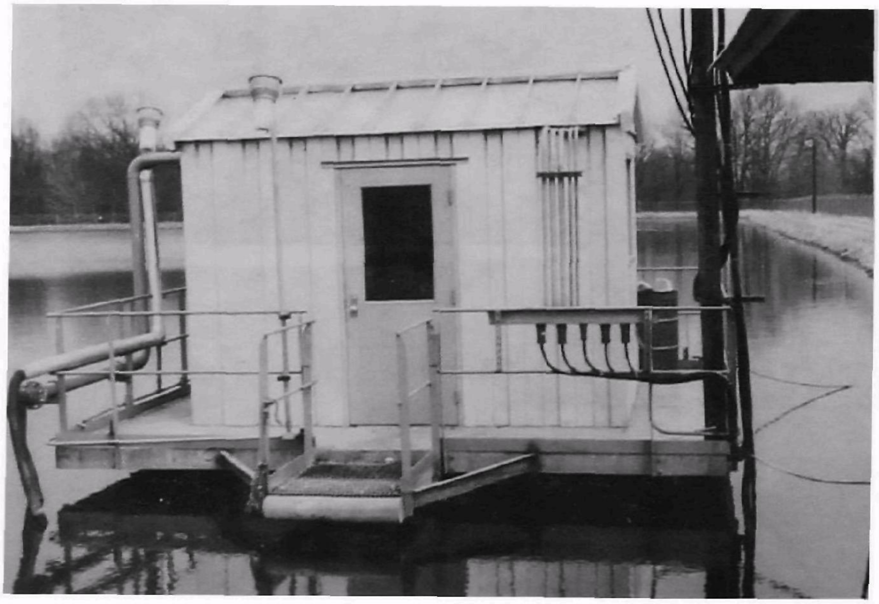
13. Close-up view of the compartmentalized recycle tank.



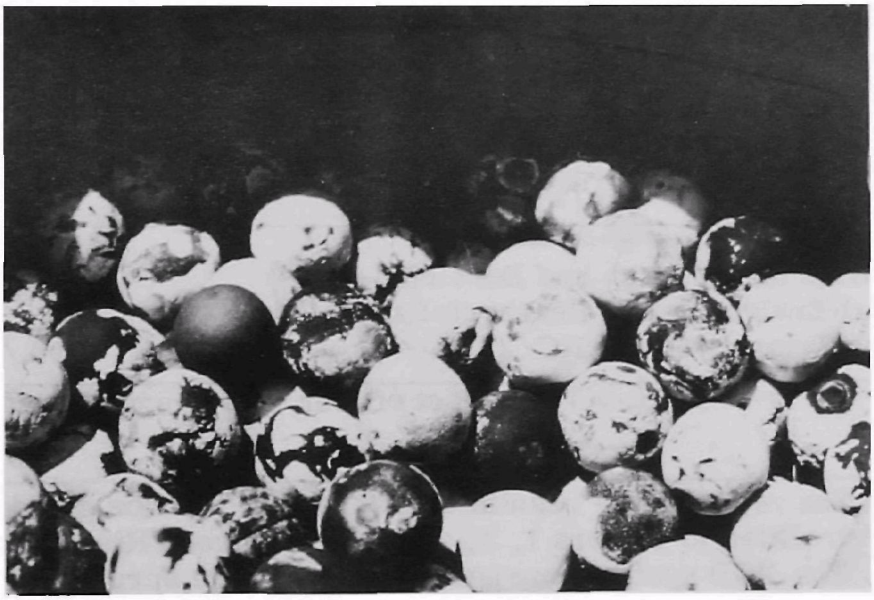
14. Close-up view of two of the six immersion-type pH sensors located in each compartment of the scrubber recycle tank.

15. Discharge and return lines for the on-site flue-gas-cleaning waste disposal area located in the background of the photograph.

16. View of the flue-gas-cleaning waste disposal area located approximately 0.8 km (0.5 mile) from the scrubber building.



17. Pump house located in the flue-gas-cleaning waste disposal area.



18. Some of the solid spheres used as packing in the mobile bed contactor of the absorber tower.

TECHNICAL REPORT DATA *(Please read Instructions on the reverse before completing)*		
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4. TITLE AND SUBTITLE Survey of Flue Gas Desulfurization Systems: Green River Station, Kentucky Utilities		5. REPORT DATE March 1978 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Bernard A. Laseke, Jr.		8. PERFORMING ORGANIZATION REPORT NO.
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15. SUPPLEMENTARY NOTES IERL-RTP project officer is Norman Kaplan, Mail Drop 61, 919/541-2556.

16. ABSTRACT The report gives results of a survey of the flue gas desulfurization (FGD) system retrofitted to Boilers 1, 2, and 3 at the Green River Station of Kentucky Utilities. The FGD system consists of one wet lime scrubber module designed to handle a maximum of 170 cu m/sec (360,000 acfm) of flue gas at 149 C (300 F). The scrubber module contains a variable-throat venturi with a flooded elbow for fly ash removal and a mobile-bed contactor for SO2 removal. The flue gas cleaning wastes are discharged from the reaction tank to an on-site clay-lined settling pond. Clear water is recycled from the pond to the system for further use. The system was started up in September 1975 and was certified commercial in January 1976. Ensuing FGD operations revealed a number of major problems which required the utility and the system supplier to repair and replace the scrubber stack shell and liner, install a steam tube air injection reheat system, and modify (and possibly replace) the system's mist eliminator. The FGD system was in service 6046 hours in 1976 and 1964 hours in 1977 (November).

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	Particulate	07A,07D	
Fly Ash	Cost Engineering			14A
Calcium Oxides	Sulfur Dioxide		07B	
Slurries	Dust Control		11G	
Ponds			08H	

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