EPA-650/2-75-057-i

October 1975

Environmental Protection Technology Series

SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS

WILL COUNTY STATION, COMMONWEALTH EDISON CO.

U.S. Environmental Protection Agency
Office of Research and Development
Washington, D. C. 20460

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WILL COUNTY STATION, COMMONWEALTH EDISON CO.

by

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Contract No. 68-02-1321, Task 6i
ROAP No. 21ACX-130
Program Element No. 1AB013

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Research Triangle Park, North Carolina 27711

Prepared for

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

October 1975

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Publication No. EPA-650/2-75-057-i

ACKNOWLEDGMENT

This report was prepared under the direction of Mr. Timothy W. Devitt. Principal authors were Dr. Gerald A. Isaacs and Mr. Fouad K. Zada.

Mr. Wade H. Ponder, former EPA Project Officer, had primary responsibility within EPA for this project report. Information and data on plant operation were provided by Mr. Mike Trykoski, Commonwealth Edison Company, and by Mr. Jack Stewart, Babcock and Wilcox Company during and subsequent to the survey visit. Mr. Charles D. Fleming was responsible for editorial review of this report.

The authors appreciate the efforts and cooperation of everyone who participated in the preparation of this report.

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SUMMARY

Boiler 1 at the Will County Station of Commonwealth Edison is a wet-bottom coal-fired boiler rated at 146 MW capacity (net). The boiler was manufactured by Babcock and Wilcox (B&W) and was installed in 1955. In 1973, the boiler burned coal with a gross heating value of 9463 BTU/lb and ash and sulfur contents of 10 percent and 2.1 percent, respectively. The wet limestone-base flue gas desulfurization (FGD) system on the boiler was also designed and installed by B&W. The FGD process is based on contacting the sulfur dioxide in the flue gas with a limestone-base slurry in the FGD modules. The FGD system, placed in service on February 23, 1972, consists of two FGD modules, limestone handling and milling facilities and a sludge treatment and stabilization unit. Each module consists of a venturi scrubber followed by a two-stage absorption tower.

Shortly after start-up and during the initial debugging stage, both modules were plagued with numerous problems. As a result, in May 1973, Commonwealth Edison shut down Module B, which was a turbulent contact absorber (TCA), to concentrate on solving the problems of Module A, which uses the countercurrent tray absorber. The performance of this

module has steadily improved, and its availability has increased since its initial start-up. Operating problems have been mainly confined to the demister and reheater units. Additional spray nozzles have been installed to keep the demister free of slurry deposits. Until an outage in November 1973, the reheater bundle slowly deteriorated as a result of pitting corrosion which occurred during down periods when steam was not maintained in the coils. Modifications to Module B included the replacement of the two TCA beds with two perforated trays and new moisture separators.

The estimated capital cost for the FGD system on Will County Unit 1 is $115/KW (net), including $13/KW for sludge treatment. Annualized operating cost is estimated to be 12 mills/KWH. These figures represent the cost of a difficult retrofit application, where the scrubbers were installed in an extremely congested space and under a construction schedule which required large overtime expenditures. These operating costs are based on an assumed boiler capacity factor of 35 percent.

Pertinent plant and FGD operational data are summarized in the following table.

SURVEY OF FGD DATA - WILL COUNTY STATION

Unit rating, MW (net)	146
Fuel	Coal
BTU/lb	9463 (10,293 design)
Ash, %	10
Sulfur, %	2.14 (4 design)
FGD vendor	B&W
Process	Wet limestone
New or retrofit	Retrofit
Start-up date	February 1972
FGD modules	Two
Efficiency, %	
Particulates	99.7 (99 design)
SO_2	82 - 90 (83 design)
Make-up water	2.08
gpm/MW (net)	2.08
Sludge disposal	Stabilized sludge disposed of in on-site, clay-lined temporary disposal basin
Unit cost	Capital estimate: $16,800,000 Annualized estimate: $5,214,000

1.0 INTRODUCTION

The Industrial Environmental Research Laboratory, (formerly the Control Systems Laboratory) of the U.S. Environmental Protection Agency (EPA) has initiated a study to evaluate the performance characteristics and degree of reliability of FGD systems on coal-fired utility boilers in the United States. This report on the Will County Station of Commonwealth Edison is one of a series of reports on such systems. It presents values of key process design and operating parameters, describes the major start-up and operational problems encountered at the facility and the measures taken to alleviate such problems, and identifies the total installed and annualized operating costs.

This report is based upon information obtained during a plant inspection on June 28, 1974 and on subsequent data provided by Commonwealth Edison personnel.

Section 2.0 presents pertinent data on facility design and operation including actual and allowable particulate and SO_2 emission rates. Section 3.0 describes the FGD system and Section 4.0 analyzes FGD system performance.

2.0 FACILITY DESCRIPTION

The Will County Station of Commonwealth Edison Company is located on the Chicago Sanitary and Ship Canal near the town of Romeoville, in Will County, Illinois. The area is heavily developed with many large refineries and chemical plants. Canal traffic consists mainly of barges carrying bulk cargo. Coal and limestone are delivered to the Will County Station by barges using this canal.

The Will County Station has four electric power generating units with a total rated capacity of 1147 MW. Only Unit 1, a wet-bottom coal-fired boiler is retrofitted with an FGD system. The capacity ratings for Unit 1 are 167 MW (gross), 153 MW (net, without FGD), and 146 MW (net, with FGD system operating). The boiler was manufactured by Babcock and Wilcox and installed in 1955.

The coal presently being burned has an average gross heating value of 9463 BTU/lb. The ash and sulfur contents are 10 and 2.1 percent, respectively.

The boiler is fitted with an electrostatic precipitator (ESP) manufactured by Joy Western Precipitation Division. The ESP has a 79 percent actual particulate collection efficiency and is generally used only when the FGD system is out of service.

The maximum particulate emission allowed under Illinois Regulation No. 2-2.11 is 0.6 lb/MM BTU of heat input to the boiler. The maximum emission allowed under the Illinois Public Commission Board Regulation No. 203(G)(1)C effective May 30, 1975, is 0.2 lb/MM BTU. The present particulate emission rate from the FGD system is equivalent to 0.06 lb/MM BTU.

Sulfur dioxide emissions are limited by the Illinois Public Commission Board Regulation No. 204(C)(1)A. Under this regulation, effective May 30, 1975, the maximum allowable SO_2 emission rate will be 1.8 lb/MM BTU. The present SO_2 emission rate, based on 82 percent removal efficiency and a maximum coal sulfur content of 4 percent, is equivalent to 1.5 lb/MM BTU. Table 2.1 presents pertinent plant and emission rate data.

Table 2.1 PERTINENT DATA ON PLANT DESIGN, OPERATION AND ATMOSPHERIC EMISSIONS - WILL COUNTY STATION

Boiler data	Item
Rated generating capacity, MW (net)	146
Average capacity factor (1973), %	52.8
Served by stack No.	1
Boiler manufacturer	Babcock & Wilcox
Year placed in service	1955
Maximum coal consumption, ton/hr	85
Maximum heat input, MM BTU/hr	1600
Stack height above grade, ft	350
Flue gas rate - maximum, acfm	770,000
Flue gas temperature, °F	355
Emission controls:	
Particulate	Venturi scrubber
SO_2	Venturi scrubber and countercurrent tray absorber
Particulate emission rates:	
Allowable, lb/MM BTU	0.2[a]
Actual, lb/MM BTU	0.06
SO_2 emission rates:	
Allowable, lb/MM BTU	1.8[a]
Actual, lb/MM BTU	1.5[b]

[a] Applicable emission rates by May 30, 1975.

[b] Based on 82 percent FGD efficiency and maximum coal sulfur content of 4 percent.

3.0 FLUE GAS DESULFURIZATION SYSTEM

3.1 PROCESS DESCRIPTION

The wet limestone FGD system at the Will County Station was placed in service on February 23, 1972. As illustrated in Figure 3.1 the system includes two FGD modules. Limestone handling and milling facilities and a sludge treatment and stabilization unit also are part of the FGD facility, but are not shown in Figure 3.1. Each module originally included a venturi scrubber followed by an absorber tower and a booster fan. Upon start-up several operational problems were encountered in both modules. In May 1973, Module B was shut down and so the concentrated efforts could be exerted on Module A to solve the problems. A principal difference between the two modules is that Module B was originally equipped with a moving plastic ball turbulent contact absorber (TCA) whereas Module A was equipped with a B&W perforated tray absorber. Module B has subsequently been modified by B&W to the perforated tray configuration.

The limestone milling system, the particulate and SO_2 scrubbing and absorbing modules, and the sludge treatment and disposal facilities are described in the following sections.

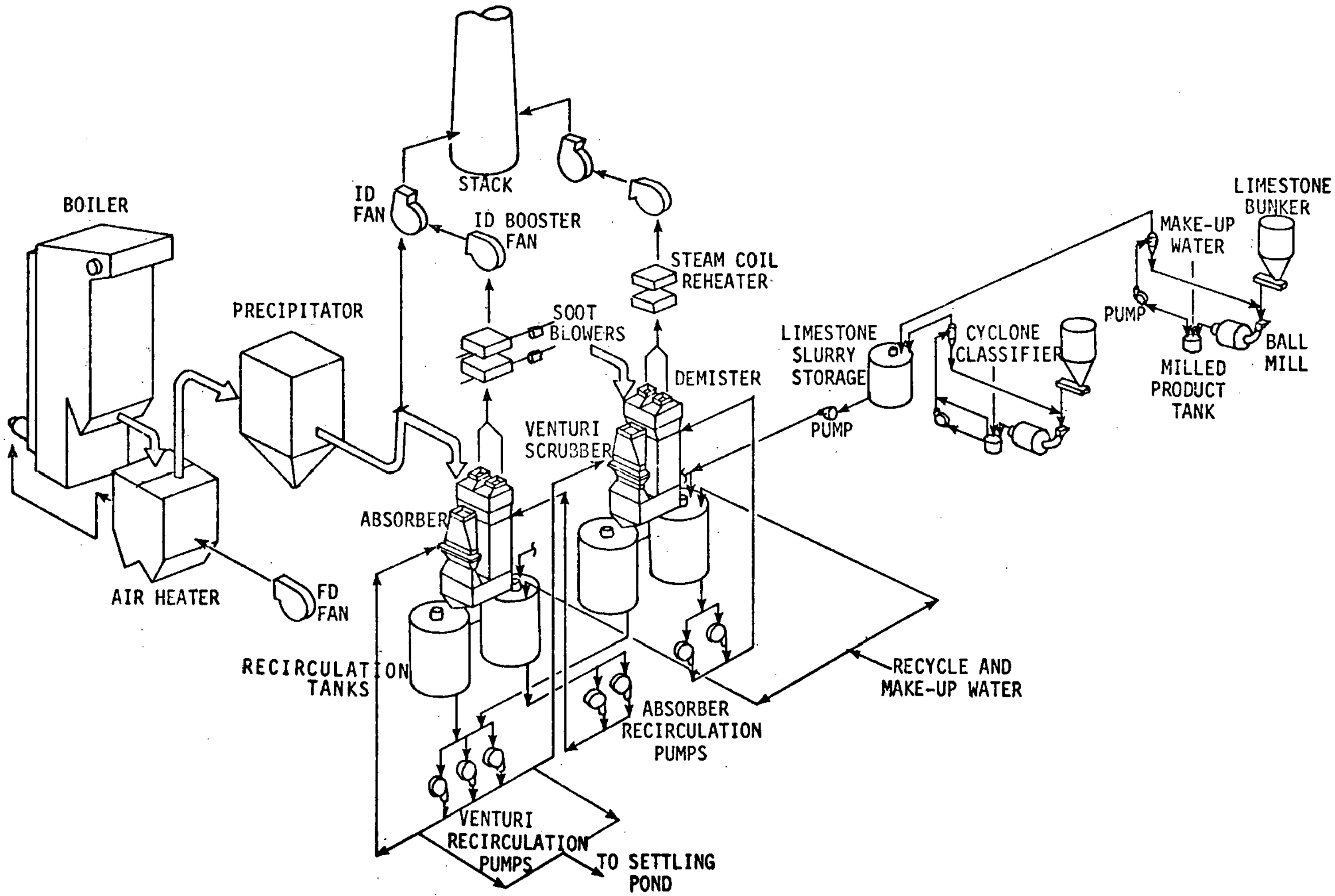


Figure 3.1 General flow diagram of the FGD system on Will County Unit 1.
(Courtesy of Commonwealth Edison Company)

3.1.1 Limestone Milling Facility

The limestone milling system consists of a limestone rock conveyor, two 260-ton capacity limestone bunkers, two wet ball mills, and a slurry storage tank. The total storage capacity of the limestone bunkers is equivalent to the limestone required for 48 hours of FGD system operation at full load. The limestone is 97.5 percent calcium carbonate and contains 0.99 percent magnesium carbonate and 0.48 percent silica. It is received in coarse ground form (about 1/2 inch or less) and is finely ground to 95 percent through 325 mesh in two wet ball mills; each ball mill is rated at 12 tons per hour. A limestone slurry containing 20 to 35 percent solids is discharged from the mills. The slurry is piped to a 4-hour capacity (62,500 gallon) storage tank, which supplies the limestone slurry to the FGD modules.

3.1.2 Particulate and SO_2 Removal Modules

Each module was designed for 385,000 acfm throughput at 355°F and handles 50 percent of the total boiler exhaust gas flow. The liquid and gas flow patterns through a typical module are shown in Figure 3.2. Flue gas passes through the existing ESP, and enters the venturi scrubber. In the venturi, the flue gas is contacted with jets of slurry sprayed from high-pressure nozzles located on each side of the rectangular venturi throat. Particulate removal efficiency is maintained by regulating the pressure drop across the adjustable venturi throat. Pressure drop across the venturi

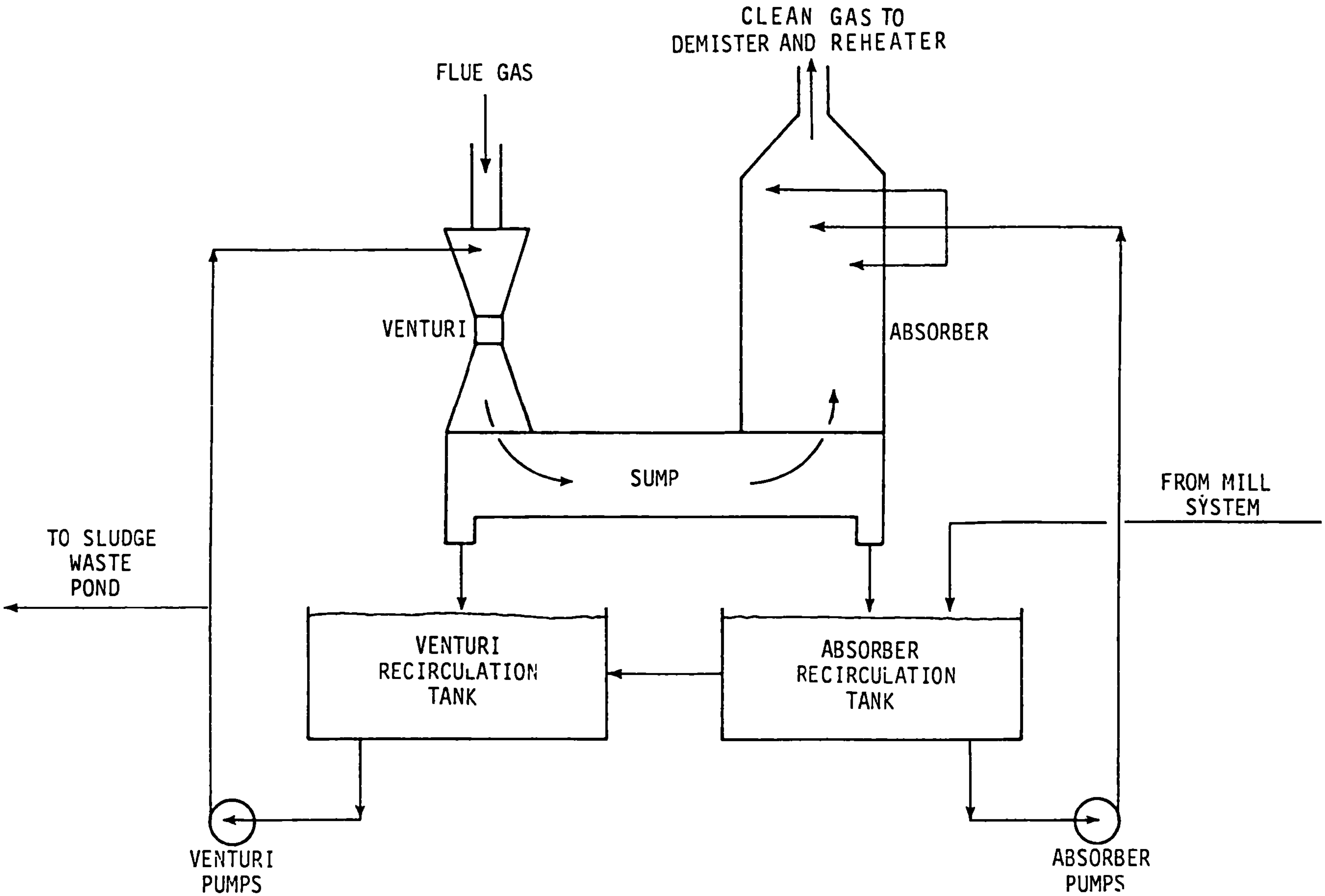


Figure 3.2 Flow diagram of a typical FGD module.

is maintained at about 9 inches of water. Gas velocity through the venturi is about 135 ft/sec.

The quenched flue gas and slurry droplets pass through the sump where the large gas velocity reduction causes the slurry droplets to drop out of the flue gas stream. The gas then flows upward through the SO_2 absorber tower and passes through two perforated trays. The trays are wetted with limestone slurry sprays located above the trays. The trays provide an extended wetted surface for absorption of SO_2 by the circulated slurry. Superficial velocity through the absorber is 12.2 ft/sec. Pressure drop through the two trays is six inches of water. Total system pressure drop is 25 inches of water.

The cleaned flue gas passes upward through a two-stage Z-shape demister. Fine mist droplets coalesce on the surface of the demister vanes and drip back into the tower. The demister is equipped with two sets of wash water headers. The lower demister is washed continuously from below by 125 gpm of fresh water. It is also washed intermittently from above by 1000 gpm of pond water for 90 seconds every two hours. The gas then enters the reheater unit, where its temperature is raised from 128°F to about 165°F. Reheat is necessary to prevent condensation in the fans, ducts and the existing brick-lined stack. The reheat also imparts plume buoyancy to suppress plume visibility.

The bare tube reheater has nine sections. The bottom three sections are made of 304 stainless steel (316L stainless steel - Module B); the other six sections are made of Corten steel. Each reheater has four soot blowers. Heat is supplied by saturated steam at 350 psig from Unit 1. Condensate from the reheater is returned to the steam circuit at the deaerator heater.

To compensate for the draft loss across each module, a booster fan was installed at the suction side of the existing boiler I.D. fan.

There are two slurry tanks for each module; the absorber recirculation tank to which fresh limestone is added and the venturi tank. Spent limestone slurry (sludge) is discharged from the venturi pump loop. These two tanks are interconnected by a common tie in such a way that the spent liquor from the absorber recirculation tank flows into the venturi circulation tank. Each tank is fitted with an agitator and pumps. The slurry recirculation rate in the absorber is about 11,000 gal./min for a liquid-to-gas ratio (L/G) of 35 gal./1000 ft^3 of gas at 120°F. The recirculation rate through the venturi is 5800 gal./min for an L/G of approximately 20 gal./1000 ft^3 of gas at 125°F. Tables 3.1, 3.2 and 3.3 summarize pertinent operating and design parameter values, plus design specifications for major process equipment.

Table 3.1 SUMMARY DATA: PARTICULATE AND SO_2 SCRUBBERS

Item	Venturi scrubber	SO_2 absorber tower
L/G ratio, gallons/1000 acf	14.5	35.5
Superficial gas velocity, ft/sec	120	12.2
Equipment sizes, ft	8 x 26 x 16 high (throat 21 x 1.8)	16 x 24 x 60 high
Equipment internals	adjustable rectangular throat blocks	two perforated trays
Material of construction		
Shell	carbon steel coated with plasite	corten steel, rubber lined
Internals	Kaocrete	316L SS

Table 3.2 SUMMARY DATA: FGD SYSTEM HOLD TANKS

Item	Venturi scrubber recirculation tank	SO_2 absorber towers recirculation tank	FGD system sludge tank	Limestone slurry make-up tank
Total number of tanks	2	2		1
Retention time at full load	8 min ea.	4 min ea.		48 hrs.
Temperature, °F	128	128	100	Ambient
pH	5.9	5.8	5.9	7
Solids concentration, %	8	8	35-40	35
Specific gravity	1.102	1.049		
Material of construction	rubber-lined carbon steel	rubber-lined carbon steel		

Table 3.3 TYPICAL PRESSURE DROP ACROSS COMPONENTS OF FGD MODULE

Equipment	Pressure drop, inches, W.G.
Venturi scrubber	9
SO_2 scrubber tower	6
Demister	1
Reheater	6
Ductwork	3
Total FGD system	25

3.1.3 Sludge Disposal System

Figure 3.3 is a flow diagram of the present sludge treatment and disposal system used at the Will County Station. The spent slurry from the two venturi loops is discharged to a 65-ft-diameter thickener. During emergencies and when the thickener is down, the slurry can be discharged directly to the pond. The overflow from the thickener is returned to the pond, but the underflow is stabilized by mixing it with lime and fly ash. About 200 lbs of lime and 400 lbs of fly ash are used per ton of dry solids of sludge. The fixed sludge is transported by concrete mixing trucks to a small on-site clay-lined basin for solidification. The stabilized sludge solidifies in about one week, depending on weather conditions.

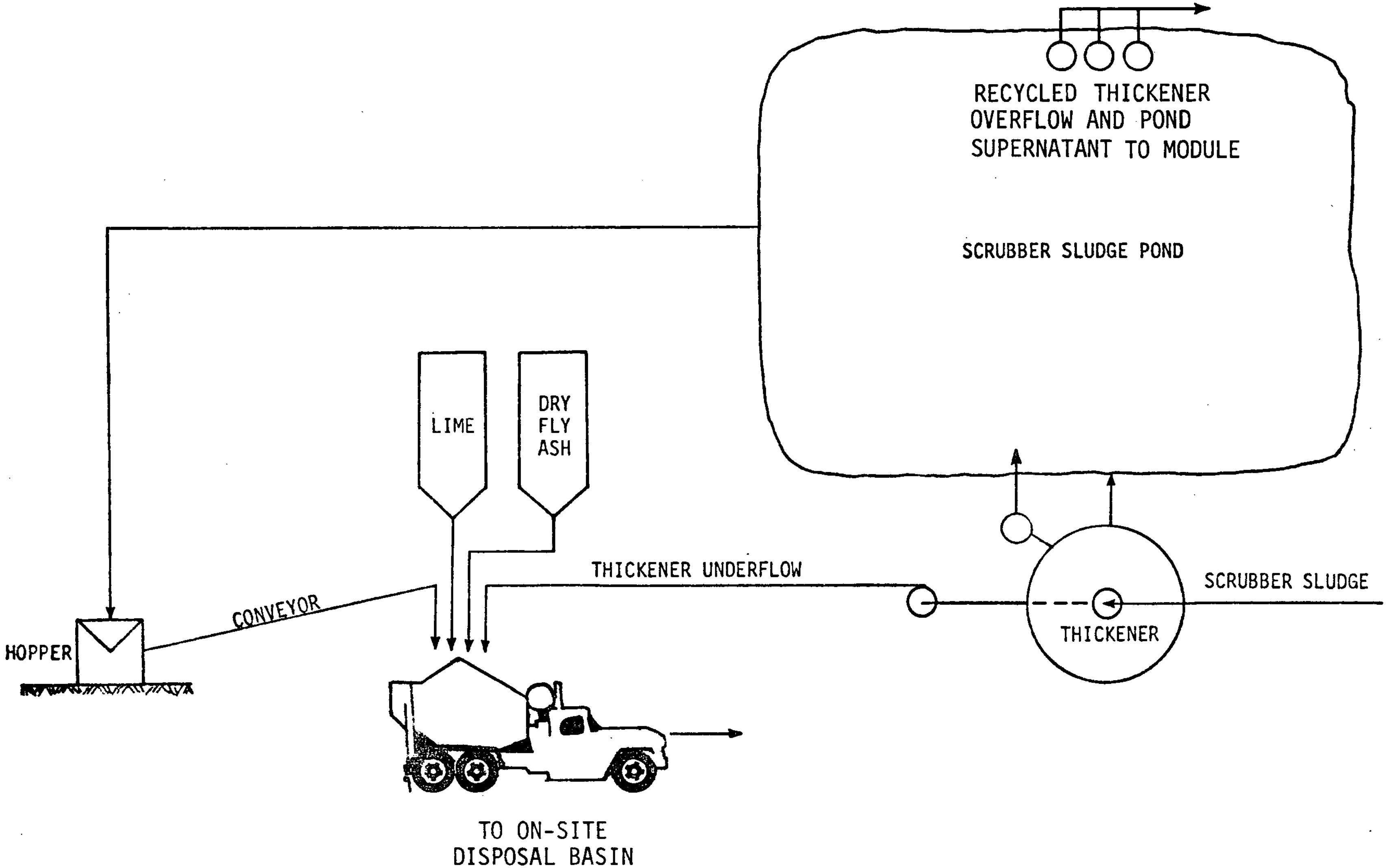


Figure 3.3 Limestone sludge stabilization facilities.

3.2 INSTALLATION SCHEDULES

Retrofitting the boiler presented several physical construction problems as well as work scheduling problems. The physical problems were due to space limitation and resulted in the sandwiching of the scrubbers between the boiler house and the service building with a substantial cantilever. Complex ductwork was also required.

B&W was authorized to begin the detailed engineering on September 3, 1970. To meet the project schedule, purchase orders were placed immediately for such long delivery items as fans, pumps, scrubbers, limestone mills and Corten steel plates. By July 1971, the bulk of the major equipment was on-site.

Equipment erection was scheduled to begin April 1, 1971, but was not underway until May 17, 1971 because of foundation problems. Soil core samples between the service building and the boiler house indicated that a slab-type foundation would be inadequate to support the FGD system column loads. Seven caissons had to be installed ranging in depth from 33 to 102 feet. Even with the late start, the equipment erection was substantially completed by the end of February 1972. Initial start-up (Module B) took place on February 23, 1972.

A detailed project construction schedule is shown in Appendix A, page A-5.

3.3 COST DATA

The estimated capital costs for the FGD system at Will County Station are presented in Table 3.4. It should be pointed out that this system is a full-size prototype demonstration unit erected under an accelerated overtime schedule and backfitted on a unit with little available space.

Estimated annual operating costs for the FGD system on Will County Unit 1 are presented in Table 3.5. A 35 percent capacity factor was used in determining the annualized costs of 10.43 mills/KWH.

Table 3.4 ESTIMATED CAPITAL INVESTMENT COSTS OF

WILL COUNTY UNIT 1 FGD SYSTEM

Gas Cleaning System	Direct cost	Indirect cost	Total cost
B&W venturi/absorber	$ 2,928,000		
Equipment erection	5,556,000		
Electrical equipment and erection	1,210,000		
Foundations	923,000		
Limestone handling system	204,000		
Professional engineering	965,000		
Mill and SO_2 buildings	193,000		
Structural steel	375,000		
Miscellaneous equipment	946,000		
	$13,300,000	$ 1,600,000	$14,900,000
Sludge Treatment System			
Thickener, pumps and truck loading station	$ 432,000		
Temporary disposal basin	141,000		
Uncommitted	1,127,000		
	$ 1,700,000	$ 200,000	$ 1,900,000
Total cost	$15,000,000	$ 1,800,000	$16,800,000
Cost per kilowatt, without sludge treatment	$ 91	$ 11	$ 102
Cost per kilowatt, with sludge treatment	$ 103	$ 12	$ 115

Notes:

(1) The cost per kilowatt is based on 146 MW net capability (167 MW -14 MW aux. power - 7 MW scrubber power = 146 MW net).

(2) This investment represents the cost of a unit retrofitted with an FGD system in an extremely congested space on a construction schedule requiring large overtime expenditures.

(3) Indirect cost is 12% of direct cost and includes such items as: certain professional services, interest during construction, payroll taxes, state use taxes, employee pensions and benefits, and administrative and legal expenses.

Table 3.5 ESTIMATED ANNUAL OPERATING COSTS OF

WILL COUNTY UNIT 1 FGD SYSTEM

(capacity factor 35%)

Gas Cleaning System	Annual cost	$/ton of coal	¢/MM BTU	Mills/KWH (net)
Carrying charge on $14,900,000	$ 2,280,000	8.40	54.0	5.09
Property tax on $14,900,000	298,000	1.10	5.6	0.67
Limestone @ $5.00/ton	230,000	0.85	4.3	0.51
Labor	88,000	0.32	1.6	0.20
Auxiliary power	454,000	1.67	8.6	1.01
Reheat Steam	82,000	0.30	1.5	0.18
Maintenance	447,000	1.65	8.4	1.00
	$ 3,879,000	14.29	73.0¢	8.67
Sludge Treatment				
Carrying charge on $1,900,000	$ 291,000	1.07	5.5	0.65
Property tax on $1,900,000	38,000	0.14	0.7	0.08
Sludge treatment @ $17.10/ton	1,006,000	3.70	19.0	2.25
	$ 1,335,000	4.91	25.2¢	2.98
Total Cost				
	$ 5,214,000	19.20	98.2¢	11.65

Notes:

Assumed life for system - 14 years.

Sludge treatment cost does not include hauling to an off-site disposal site nor the disposal site fee

Assumes that the FGD system availability equals boiler-turbine availability.

Capacity factor of 35% assumed for above calculations.

Total Costs Assuming Alternative Capacity Factors

	Annual cost	$/ton of coal	¢/MM BTU	Mills/KWH (net)
@ 50% capacity factor	5,838,000	15.05	77.0	9.13
@ 65% capacity factor	6,463,000	12.81	65.2	7.77

4.0 FGD SYSTEM PERFORMANCE

4.1 PERFORMANCE TEST RUNS

During May and August 1972, preliminary performance tests were made by B&W. The outlet dust loading, during the May test, varied from 0.0073 to 0.0334 grains per standard cubic foot (gr/scf) of gas. The guaranteed outlet dust loading was 0.0248 gr/scf. The outlet sulfur dioxide values are not applicable to the guarantee because a varying blend of western low-sulfur coal and Illinois high-sulfur coal was being burned. The SO_2 removal efficiency was 90 percent under normal conditions, and 67 percent under conditions when limestone feed to the unit was intentionally reduced. A partial summary of the test data is presented in Table 4.1.

During the August test runs, the outlet dust loading varied from 0.0213 to 0.0278 gr/scf. These results were obtained while burning Illinois high-sulfur coal. A partial summary of the test data appears in Table 4.2. SO_2 removal efficiencies are comparable with the May test results. Some SO_2 removal efficiency data are presented in Table 4.3.

All test runs were made on Module A with the existing ESP deenergized.

Table 4.1 WILL COUNTY UNIT 1 WET SCRUBBER MODULE A

PRELIMINARY TEST DATA - MAY 18 - 23, 1972

Test number	1	2	3	4	5	6	7	8	9	10	11	12
Date	5-18	5-18	5-19	5-19	5-20	5-20	5-21	5-21	5-22	5-22	5-23	5-23
Load, MW	113	113	114	115	111	112	113	115	110	111		58
Gas flow, acfm x 10^{-3}	335	355	335	340	335	320	315	310	315	335	205	215
Scrubber system, pressure difference, inches H_2O	24.5	29	21	25	24	25.5	22.5	22.0	23.2	23.0	16.0	18.0
Dust inlet, gr/DSCF		0.0944	0.1440	0.1470	0.1105	0.1790			0.3060	0.2580		
Dust outlet, gr/DSCF	0.0232	0.0079	0.0073	0.0298	0.0261	0.0255			0.0205	0.0334		
SO_2 inlet, ppm	1145	1140	890	930	1130	1000	640	910	1000	545	1200	1150
SO_2 outlet, ppm	67	75	294	35	285	118	18	45	223	180	45	50
SO_2 removal efficiency, %	94	93	67	96	75	88	97	95	81	67	96	96
Absorber slurry solids concentration, %	3.4	5.2	5.5	5.2	2.5	4.3	5.0		2.9	2.2		1.5
Absorber pH	6.5	6.3	7.4	6.3	5.7	5.8	7.2	5.7	5.9	5.4	6.1	6.1

4.2 START-UP AND OPERATING PROBLEMS AND SOLUTIONS

As mentioned earlier, numerous problems have occurred since start-up of the FGD system in February 1972. Many problems have been completely solved; substantial progress has been made on others. The FGD system availability for Module A has improved consistently throughout 1974. It is expected that when Module B is modified, its performance and availability will be comparable to that of Module A. Monthly availability data factors for each module are presented in Table 4.4.

The major problems encountered and their solutions are discussed below.

1972 - Demister plugging was a constant problem, mainly because of heavy limestone slurry accumulations on the bottom of the demister. This problem kept Modules A and B out of service for several days per month during March, April, June and July 1972. The modules were also out of service from September 26 to November 21, 1972, because the boiler was down during that period.

Because of heavy demister plugging the demister washer nozzles were relocated to spray upward onto the bottom (upstream side) of the demister. The spray modifications improved the demister washing operation considerably.

Starting on March 12, a 15-day run with Module A was completed with only three minor outages totaling ten hours. One outage was an operating error trip. Two were attributed

Table 4.2 WILL COUNTY UNIT 1 ~~WET SCRUBBER~~ MODULE A

PRELIMINARY TEST DATA - JULY AND AUGUST 1972

Test number	1	2	3	4	5	6
Date	7-25	7-26	7-27	8-4	8-4	8-7
Load, MW	102	100	112	104	103	98
Gas flow, acfm x 10^{-3}	326	276	364	383	383	400
Scrubber system, pressure difference, inches H_2O	20	14.5	23.5	26	27	26
Dust inlet, gr/DSCF	0.4354	0.2508	0.1855	0.2075	0.1008	0.2339
Dust outlet, gr/DSCF	0.0213	0.0228	0.0220	0.0229	0.0222	0.0278
Absorber slurry solids concentration, %	2	2	2	2	11	11.8
Absorber pH	4.7	5.7		6.0	6.2	6.2

Table 4.3 WILL COUNTY UNIT 1 MODULE A

PRELIMINARY TEST DATA - AUGUST 8-12, 1972

Test number	1	2	3	4	5	6	7	8	9	10
Date	8-8	8-8	8-9	8-9	8-10	8-10	8-11	8-11	8-12	8-12
Gas flow, acfm x 10^{-3}	360	360	226	353	360	353	345	468	370	370
Scrubber system, pressure difference, inches H_2O	26.5	26.0	21.0	29.0	28.0	27.0	26.0	28.0	28.0	29.5
SO_2 inlet, ppm	2400	2860	2720	2680	2700	1065	1600	2230	2260	2350
SO_2 outlet, ppm	300	960	495	800	185	63	280	570	520	765
SO_2 removal efficiency, %	87.5	66.4	81.8	70.0	93.2	94.1	82.5	74.4	77.0	67.3
Absorber, pH	5.7	5.9	4.9	5.0	5.5	6.6	6.4			

Table 4.4 FGD SYSTEM AVAILABILITY FACTORS

Period Month/year	Availability, % Module A	Availability, % Module B	Period Month/year	Availability, % Module A	Availability, % Module B	Period Month/year	Availability, % Module A	Availability, % Module B
March, 1972	0	35	April	6	13	July	96	0
April	34	14	May	0	0	August	91	0
May	69	32	June	1	0	September	85	0
June			July	51	0	October	94	0
July			August	19	0	November	97	0
August	79	21	September	0	0	December	99	0
September	0	29	October	32	0	January 1975	99	0
October	0	0	November	51	0	February	99	0
November	0	0	December	0	0	March	99	0
December	22	30	January 1974	0	0			
January 1973	0	0	February	0	0			
February	22	24	March	21	0			
March	65	11	April	72	0			
			May	93	0			
			June	54	0			

to "limestone blinding", a reported unexplained phenomenon characterized by a sudden drop in SO_2 removal efficiency and a pH reduction that cannot be readjusted by the addition of limestone.[a] In this case the odor of sulfur dioxide was very strong over the recirculation tanks. When the phenomenon occurred several months earlier, proper operation was recovered without isolating the scrubber from the boiler by lowering the recirculating tank level and refilling with fresh limestone slurry. During these two later occurrences it was necessary to remove the scrubber from service.

During high gas flow rates, the reheater of Module B vibrated excessively. Therefore, Module B was taken out of service in April 1972 to carry out reheater modifications. These modifications included rebracing the reheater tubes and installing a baffle plate to reduce the vibrations.

Other reasons for module outages included erosion and plugging of spray nozzles, internal and external buildup of deposits on venturi nozzles, corrosion cracking and fan vibrations.

1973 - Demister plugging continued to be a problem. Furthermore, the demister on Module B broke loose from its mountings and the resultant carryover wash water plugged the reheater. The reheater also began to leak from chloride corrosion. Module A was down from April 24 to May 24, 1973,

---

[a] EPA has reported only one isolated case of the occurrence of blinding several years ago at TVA's Colbert Station. The phenomenon was not confirmed in tests at Shawnee where the pH was intentionally lowered. When the limestone feed was restored, the pH recovered and the system resumed normal, satisfactory operation.

and Module B has been inoperative since April. The FGD system was not operated between August 27 and September 26, 1973.

To solve the existing demister and reheater problems, a constant underspray and an intermittent overspray were used to wash all the demister compartments of Module A. Extra nozzles were added and a clean water supply was maintained. The failed reheaters were retubed using the best tubes from both modules.

1974 - Only Module A was operated in 1974. The demister operated satisfactorily; manual cleaning of demister, reheater and absorber trays was not required. Operating problems included damaged piping, sump pumps and instrumentation due to freezing weather, and steam piping leaks. Fan balance problems were reported, but the fans were not cleaned during 1974.

1975 - Module A performed with high reliability through May. Most outages through then were either for inspection purposes or else were due to the lack of demand for power. Reheater leaks and plugged demister wash nozzles have occurred. The module was shut down in June and remained out of service throughout July. A new replacement demister was being installed in July, and the reheater has been removed. A new reheater has been ordered. The module will remain out of service until the new demister and the replacement reheater have been installed.

Module B was placed in service on May 20, 1975. Early outages have been related to booster fan deposits and vibrations. Reheater leaks have occurred after 1000 hours of operation and appear to be due to vibration fatigue.

APPENDIX A

PLANT SURVEY FORM

PLANT SURVEY FORM

NON-REGENERABLE FGD PROCESSES

A. COMPANY AND PLANT INFORMATION

1. COMPANY NAME Commonwealth Edison Company
2. MAIN OFFICE P.O. Box 767 - Chicago, Illinois 60690
3. PLANT MANAGER James R. Gilbert
4. PLANT NAME Will County Station
5. PLANT LOCATION Romeoville, Illinois
6. PERSON TO CONTACT FOR FURTHER INFORMATION Mr. J.P. McCluskey[a]
7. POSITION Director - Environmental Affairs
8. TELEPHONE NUMBER 312/294-2921
9. DATE INFORMATION GATHERED 6/28/74
10. PARTICIPANTS IN MEETING AFFILIATION

PARTICIPANTS IN MEETING	AFFILIATION

[a] These data were reported on 6/28/74. Some of the data have been updated in the text of the report.

B. PLANT DATA. (APPLIES TO ALL BOILERS AT THE PLANT).

		BOILER NO.				
		1	2	3	4	
CAPACITY, MW	Gross/ Net	167/144	167/154	278/262	545/523	
SERVICE (BASE, PEAK)		Cycling	Cycling	Base	Base	
FGD SYSTEM USED		Wet limestone	None	None	None	

C. BOILER DATA. COMPLETE SECTIONS (C) THROUGH (R) FOR EACH BOILER HAVING AN FGD SYSTEM.

1. BOILER IDENTIFICATION NO. 1
*2. MAXIMUM CONTINUOUS HEAT INPUT 1600 MM BTU/HR
3. MAXIMUM CONTINUOUS GENERATING CAPACITY 167 MW (GROSS)
4. MAXIMUM CONTINUOUS FLUE GAS RATE, 770,000 ACFM @ 355°F
5. BOILER MANUFACTURER Babcock and Wilcox
6. YEAR BOILER PLACED IN SERVICE 1955
7. BOILER SERVICE (BASE LOAD, PEAK, ETC.) Cycling
8. STACK HEIGHT 350'
9. BOILER OPERATION HOURS/YEAR (197) 7632
10. BOILER CAPACITY FACTOR * 52.8%
11. RATIO OF FLY ASH/BOTTOM ASH 20/80
    (Industry accepted values for cyclone-fired boiler)

$$\text{* DEFINED AS: } \frac{\text{KWH GENERATED IN YEAR}}{\text{MAX. CONT. GENERATED CAPACITY IN KW x 8760 HR/YR}}$$

D. FUEL DATA (1973) - One year average

1. COAL ANALYSIS (as received)

	MAX.	MIN.	AVG.
GHV (BTU/LB.)	9903	8963	9463
S %	3.01	0.61	2.14
ASH %	12.50	5.11	9.99

2. FUEL OIL ANALYSIS (exclude start-up fuel) (NONE)

GRADE			
S %			
ASH %			

E. ATMOSPHERIC EMISSIONS

1. APPLICABLE EMISSION REGULATIONS

	PARTICULATES	SO_2
a) CURRENT REQUIREMENTS		
AQCR PRIORITY CLASSIFICATION		
REGULATION & SECTION NO.	Ill. Rules & Regs. governing the control of air poll. rule 2-2.11	
MAX. ALLOWABLE EMISSIONS LBS/MM BTU	0.6	--
b) FUTURE REQUIREMENTS, COMPLIANCE DATE	5/30/75	5/30/75
REGULATION & SECTION NO.	IPCB Air Pollution Regs. 203(G)(1) C	204(C)(1) A
MAXIMUM ALLOWABLE EMISSIONS LBS/MM BTU	0.2	1.8

2. PLANT PROGRAM FOR PARTICULATES COMPLIANCE

All units presently in compliance with 1975 standards.

3. PLANT PROGRAM FOR SO_2 COMPLIANCE

All units presently in compliance with 1975 standards.

* ESP Normally not used, except when scrubber is out of service.

F. PARTICULATE REMOVAL

1. TYPE	MECH.	* E.S.P.	FGD
MANUFACTURER		Western	B&W
EFFICIENCY: DESIGN/ACTUAL		90/79	99/98
MAX. EMISSION RATE* LB/HR		845	99.2
GR/SCF (70°F)		0.29	0.024
LB/MMBTU		0.55	0.06

DESIGN BASIS, SULFUR CONTENT 4.0%

G. DESULFURIZATION SYSTEM DATA

1. PROCESS NAME Wet limestone scrubbing
2. LICENSOR/DESIGNER NAME: Babcock and Wilcox
   ADDRESS: Barberton, Ohio
   PERSON TO CONTACT: Mr. Thomas Hurst
   TELEPHONE NO.: 216/753-4511
3. ARCHITECTURAL/ENGINEERS, NAME: Bechtel Power Corp.
   ADDRESS: Fifty Beale Street San Francisco, California
   PERSON TO CONTACT: Mr. J. J. Smortchevsky
   TELEPHONE NO.: 415/764-6262
4. PROJECT CONSTRUCTION SCHEDULE: DATE
   a) DATE OF PREPARATION OF BIDS SPECS. June, 1970
   b) DATE OF REQUEST FOR BIDS August, 1970
   c) DATE OF CONTRACT AWARD September 28, 1970
   d) DATE ON SITE CONSTRUCTION BEGAN May 17, 1971
   e) DATE ON SITE CONSTRUCTION COMPLETED April, 1972
   f) DATE OF INITIAL STARTUP('B' Module only) February 23, 1972
   g) DATE OF COMPLETION OF SHAKEDOWN Still in Progress

*At Max. Continuous Capacity

5. LIST MAJOR DELAYS IN CONSTRUCTION SCHEDULE AND CAUSES:

Ref: Will County Unit 1 Limestone Wet Scrubber Description and Operating Experience, by D.C. Gifford, Commonwealth Edison Company, Chicago, Illinois, November 30, 1973.

6. NUMBER OF SO_2 SCRUBBER TRAINS USED 2

7. DESIGN THROUGHPUT PER TRAIN, ACFM @ 355°F 385,000

8. DRAWINGS: 1) PROCESS FLOW DIAGRAM AND MATERIAL BALANCE

2) EQUIPMENT LAYOUT (See attach 1)

H. SO_2 SCRUBBING AGENT

1. TYPE Limestone

2. SOURCES OF SUPPLY Marblehead lime Office in Chicago - quarry around St. Louis --- or Quincy

3. CHEMICAL COMPOSITION (for each source)

SILICATES

SILICA 0.48%

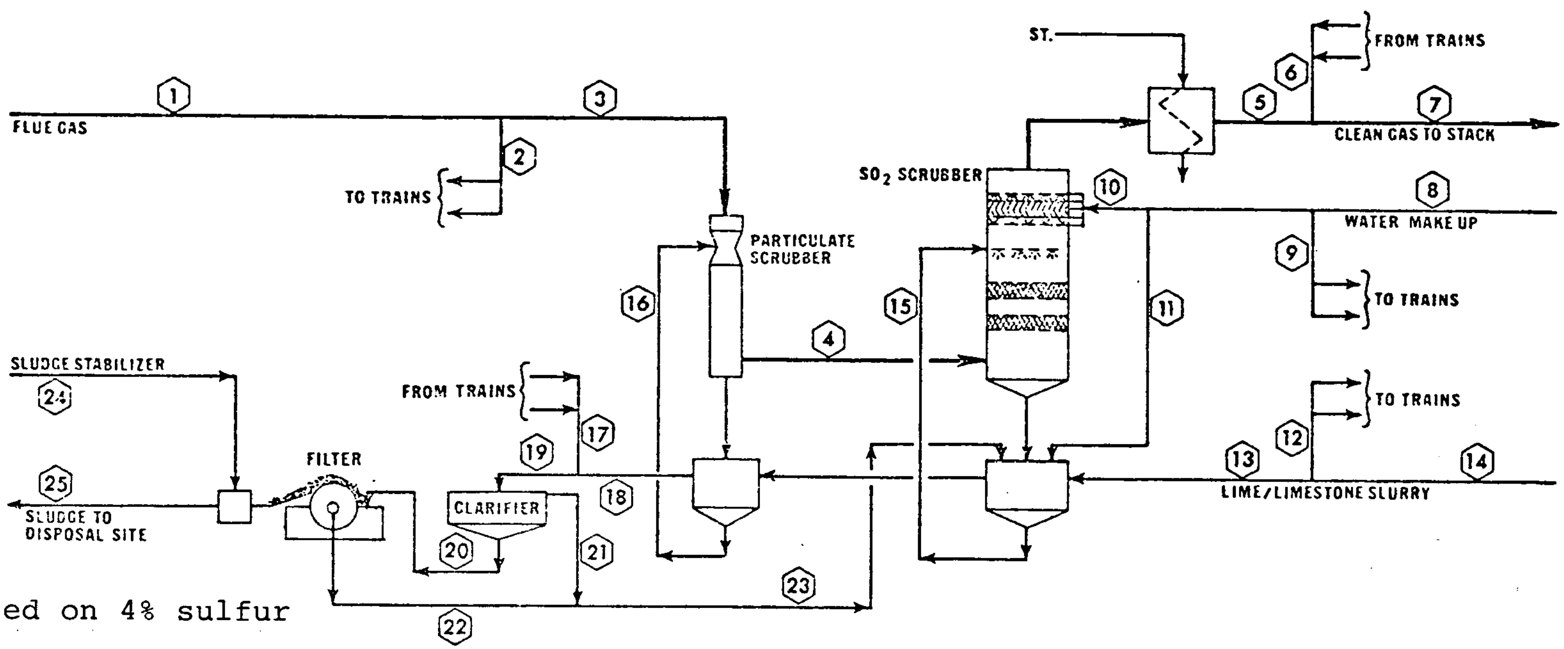
CALCIUM CARBONATE 97.5%

MAGNESIUM CARBONATE 0.99%

4. EXCESS SCRUBBING AGENT USED ABOVE STOICHIOMETRIC REQUIREMENTS 30 - 50%

5. MAKE-UP WATER POINT OF ADDITION Absorber Recirc. Tank and demister underspray

6. MAKE-UP ALKALI POINT OF ADDITION Absorber Recirc. Tank



Based on 4% sulfur

Contract design Number 1 remainder are actual experience

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13
RATE, lb/hr													
ACFM	770,000	385,000	385,000	315,000	354,000	354,000	708,000						
GPM								280	140	140	0	60	60
PARTICULATES, lb/hr	4960	2480	2480	49.6	49.6	49.6	99.2						
SO_2, lb/hr	12,360	6180	6180	4120	1135	1135	2270	–	–	–	–	–	–
TEMPERATURE, °F	355	355	355	128	200	200	200	80	80	80	–	80	80
TOTAL SOLIDS, %												35	35
SPECIFIC GRAVITY,												1.3	1.3

STREAM NO.	14	15	16	17	18	19	20	21	22	23	24	25	26
RATE, lb/hr											9700	90,522	
ACFM												–	
GPM	120	11,200	5600	250	250	500	120	330	–	330		–	
PARTICULATES, lb/hr													
SO_2, lb/hr													
TEMPERATURE, °F	80	120	120	120	120	120	100	100	–	100		80	
TOTAL SOLIDS, %	35	10%	10%	10	10	10	40	0	–	0		46%	
SPECIFIC GRAVITY	1.3	1.07	1.07	1.07	1.07	1.07	1.33	1.0	–	1.0		1.4	

I. Representative flow rates based on operating data at maximum continuous load

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J. SCRUBBER TRAIN SPECIFICATIONS

1. SCRUBBER NO. 1 [(a)] (Particulate Removal)

TYPE (TOWER/VENTURI)	Venturi
LIQUID/GAS RATIO, G/MCF @ 355°F	14.5 - full load
GAS VELOCITY THROUGH SCRUBBER, FT/SEC	120
MATERIAL OF CONSTRUCTION	Carbon Steel
TYPE OF LINING	Plastic and two inch Kaocrete
INTERNALS:	
TYPE (FLOATING BED, MARBLE BED, ETC.)	Moveable Throat Block
NUMBER OF STAGES	One
TYPE AND SIZE OF PACKING MATERIAL	N/A
PACKING THICKNESS PER STAGE [(b)]	
MATERIAL OF CONSTRUCTION, PACKING:	N/A
SUPPORTS:	N/A

2. SCRUBBER NO. 2 [(a)] (SO_2 Removal)

TYPE (TOWER/~~VENTURI~~)	Tower
LIQUID/GAS RATIO, G/MCF @ 120°F	35.5 - full load
GAS VELOCITY THROUGH SCRUBBER, FT/SEC	10
MATERIAL OF CONSTRUCTION	Corten Steel
TYPE OF LINING	Rubber
INTERNALS:	
TYPE (FLOATING BED, MARBLE BED, ETC.)	Perforated Plates
NUMBER OF STAGES	2
TYPE AND SIZE OF PACKING MATERIAL	None

a) Scrubber No. 1 is the scrubber that the flue gases first enter. Scrubber 2 (if applicable) follows Scrubber No. 1.

b) For floating bed, packing thickness at rest.

PACKING THICKNESS PER STAGE[b] N/A

MATERIAL OF CONSTRUCTION, PACKING: N/A

SUPPORTS: N/A

3. CLEAR WATER TRAY (AT TOP OF SCRUBBER)

TYPE N/A

L/G RATIO N/A

SOURCE OF WATER N/A

4. DEMISTER

TYPE (CHEVRON, ETC.) Chevron

NUMBER OF PASSES (STAGES) 2-separated by 4' of space

SPACE BETWEEN VANES 1-3/4"

ANGLE OF VANES 45°

TOTAL DEPTH OF DEMISTER 7"

DIAMETER OF DEMISTER Rectangular Shape

DISTANCE BETWEEN TOP OF PACKING AND BOTTOM OF DEMISTER 7'

POSITION (HORIZONTAL, VERTICAL) Horizontal

MATERIAL OF CONSTRUCTION FRP

METHOD OF CLEANING Water Spray, Bottom - Constant Top - Intermittent

SOURCE OF WATER AND PRESSURE Bottom - Fresh (15 psig) Top - Pond (30 psig)

FLOW RATE DURING CLEANINGS, GPM Bottom - 120 gpm/module Top - 1000gpm/compartment(3)

FREQUENCY AND DURATION OF CLEANING Bottom - Constant Top - 30 sec. every 2 hour

REMARKS 2nd demister installed end of March, 1974

5. REHEATER

TYPE (DIRECT, INDIRECT) Indirect Steam

b) For floating bed, packing thickness at rest.

DUTY, MMBTU/HR 55

HEAT TRANSFER SURFACE AREA SQ.FT 6096 (total)

TEMPERATURE OF GAS: IN 128 OUT 200°F

HEATING MEDIUM SOURCE Steam from boiler

TEMPERATURE & PRESSURE 485°F, 350 psig

FLOW RATE 55,000 LB/HR

REHEATER TUBES, TYPE AND MATERIAL OF CONSTRUCTION 5/8" - 304 SS and Corten Steel

REHEATER LOCATION WITH RESPECT TO DEMISTER

After demister

METHOD OF CLEANING Sootblowers (8)

FREQUENCY AND DURATION OF CLEANING Every 4 hours

FLOW RATE OF CLEANING MEDIUM Unknown LB/HR

REMARKS

6. SCRUBBER TRAIN PRESSURE DROP DATA

	INCHES OF WATER
PARTICULATE SCRUBBER	9
SO_2 SCRUBBER	6
CLEAR WATER TRAY	-
DEMISTER	1
REHEATER	6
DUCTWORK	3
TOTAL FGD SYSTEM	25

7. FRESH WATER MAKE UP FLOW RATES AND POINTS OF ADDITION (Total for Both Modules)

TO: DEMISTER 240 gpm

QUENCH CHAMBER --

ALKALI SLURRYING --

PUMP SEALS 60 gpm

OTHER

TOTAL 300 gpm

FRESH WATER ADDED PER MOLE OF SULFUR REMOVED 880*lb. H_2O/lb. Mole SO_2 Removed

8. BYPASS SYSTEM

CAN FLUE GAS BE BYPASSED AROUND FGD SYSTEMS Yes

GAS LEAKAGE THROUGH BYPASS VALVE, ACFM Unknown

K. SLURRY DATA

	pH	% Solids	Capacity (gal)	Hold up time
LIME/LIMESTONE SLURRY MAKEUP TANK	7.0	35	60,000	N/A
PARTICULATE SCRUBBER EFFLUENT HOLD TANK (a)	5.9	8	40,000	8 min.
SO_2 SCRUBBER EFFLUENT HOLD TANK (a)	5.8	8	40,000	4 min.

L. LIMESTONE MILLING AND CALCINING FACILITIES: INDICATE BOILERS SERVED BY THIS SYSTEM.

TYPE OF MILL (WET CYCLONE, ETC.) Wet Ball

NUMBER OF MILLS 2

CAPACITY PER MILL 12 T/HR

RAW MATERIAL MESH SIZE 0 X 1/2"

PRODUCT MESH SIZE 95% < 325

SLURRY CONCENTRATION IN MILL 60%

CALCINING AND/OR SLAKING FACILITIES N/A

SOURCE OF WATER FOR SLURRY MAKE UP OR SLAKING TANK Pond recycle

M. DISPOSAL OF SPENT LIQUOR

1. SCHEMATICS OF SLUDGE & FLY ASH DISPOSAL METHOD

   (IDENTIFY QUANTITIES OR SCHEMATIC) See Page 6

2. CLARIFIERS (THICKENERS)

   NUMBER 1

   DIMENSIONS 65% dia. X 15' high

   CONCENTRATION OF SOLIDS IN UNDERFLOW 35-40%

3. ROTARY VACUUM FILTER

   NUMBER OF FILTERS N/A

   CLOTH AREA/FILTER N/A

   CAPACITY N/A TON/HR (WET CAKE)

   CONCENTRATION OF SOLIDS IN CAKE N/A

   PRECOAT (TYPE, QUANTITY, THICKNESS) N/A

   REMARKS ______

4. SLUDGE FIXATION

   POINT OF ADDITIVES INJECTION Thickener underflow

   FIXATION MATERIAL COMPOSITION Lime and fly ash

   FIXATION PROCESS (NAME) None

   FIXATION MATERIAL REQUIREMENT/TONS OF DRY SOLIDS OF SLUDGE

   0.1 ton lime and 0.2 ton fly ash

ESTIMATED POND LIFE, YRS. 1/2 yr.

CONCENTRATION OF SOLIDS IN FIXED SLUDGE 46%

METHOD OF DISPOSAL OF FIXED SLUDGE Lined basin - clay[a]

INITIAL SOLIDIFICATION TIME OF FIXED SLUDGE 1 week, but varies with ambient

5. SLUDGE QUANTITY DATA

POND/LANDFILL SIZE REQUIREMENTS, ACRE-FT/YR 150

IS POND/LANDFILL ON OR OFFSITE On

TYPE OF LINER Clay

IF OFFSITE, DISTANCE AND COST OF TRANSPORT N/A

POND/LANDFILL DIMENSIONS AREA IN ACRES 7
DEPTH IN FEET 10

DISPOSAL PLANS; SHORT AND LONG TERM

Short term plans are to continue using present disposal basin. Long term plans are to dispose of treated sludge in a disposal site near the station. Awaiting Illinois EPA approval of site.

N. COST DATA (See attach 1)

1. TOTAL INSTALLED CAPITAL COST (Direct)

2. ANNUALIZED OPERATING COST

[a] About 1 foot deep.

3. COST BREAKDOWN

	COST ELEMENTS	INCLUDED IN ABOVE COST ESTIMATE YES	NO	ESTIMATED AMOUNT OR % OF TOTAL INSTALLED CAPITAL COST
A.	CAPITAL COSTS			Direct cost/Total cost = Direct cost + Indirect @ 12%
	SO_2 SCRUBBER TRAINS	X		2,928,000/3,279,000
	LIMESTONE MILLING FACILITIES	X		397,000/445,000
	SLUDGE TREATMENT & DISPOSAL POND	X		573,000/642,000
	SITE IMPROVEMENTS	X		Appears in contractor's fee
	LAND, ROADS, TRACKS, SUBSTATION	X		Appear in contractor's fee
	ENGINEERING COSTS	X		965,000/1,081,000
	CONTRACTORS FEE*	X		9,010,000/10,091,000
	INTEREST ON CAPITAL DURING CONSTRUCTION		X	Not available
B.	ANNUALIZED OPERATING COST **			
	FIXED COSTS			
	INTEREST ON CAPITAL	X		2,280,000
	DEPRECIATION	X		Included in above figure
	INSURANCE & TAXES		X	Not available
	LABOR COST INCLUDING OVERHEAD	X		88,000
	VARIABLE COSTS			
	RAW MATERIAL	X		230,000
	UTILITIES	X		454,000
	MAINTENANCE	X		447,000

* Contractors Fee Includes: Equipment Erection, Electrical Equipment & Erection, Foundations, Structural Steel and Miscellaneous Equipment.

** Estimated annual operating cost @ 35% boiler capacity factor.

4. COST FACTORS

a. ELECTRICITY — $454,000/yr.

b. WATER — Pumping cost only - included in (a)

c. STEAM (OR FUEL FOR REHEATING) — $ 82,000/yr.

*d. FIXATION COST 16.20 $/TON OF DRY SLUDGE

**e. RAW MATERIAL PURCHASING COST 7.55 $/TON OF DRY SLUDGE

f. LABOR: SUPERVISOR ________ HOURS/WEEK ______ WAGE

OPERATOR ________ ______

OPERATOR HELPER ________ ______

MAINTENANCE @ 40 hrs/wk @ $15/hr includes supervisor

[a] Contract out thru B&W = 5 people

O. MAJOR PROBLEM AREAS: (CORROSION, PLUGGING, ETC.)

1. SO_2 SCRUBBER, CIRCULATION TANK AND PUMPS.

a. PROBLEM/SOLUTION

Scaling on Absorber Plates, Scale breaking of Venturi Throat and Venturi Sumpwalls plugging Recirc. Tank Screen. -- Solutions unknown at present.

2. DEMISTER

PROBLEM/SOLUTION

Plugging -- Improved washing systems have partially alleviated the problem.

3. REHEATER

PROBLEM/SOLUTION Deposits -- Improvement in Demister Efficiency. Corrosion (Chloride) -- Improvement in Demister Efficiency has helped, but may require new reheater tube alloy.

* Includes raw material(e) but not cost of disposal site.

** Limestone - $3.84, Lime - $3.38, Fly ash - $0.33.

4. VENTURI SCRUBBER, CIRCULATION TANKS AND PUMPS

PROBLEM/SOLUTION

Wet-dry interface deposit, Throat drive problems, Tank screen scaling causing screen blockage and collapse -- Not solved yet.

5. I.D. BOOSTER FAN AND DUCT WORK

PROBLEM/SOLUTION

Corrosion of ductwork - not solved.

Booster fan swinging - control modification.

Inlet cone cracks - rewelded.

Acid deposits caused by low reheat temp. - raised temperature

Vibration - rebalanced fan.

6. LIMESTONE MILLING SYSTEM OR LIME SLAKING

PROBLEM/SOLUTION Limestone hangs up in silo -- installing air operated flow stimulators, hopefully this will solve problem.

Chutes Plug -- Installed new reversible conveyor. Level indication in tanks, throttling slurry flow due to valve wear, pump inlet expansion joint failures -- Not solved yet.

Pluggage of piping -- Piping redesign has helped.

7. SLUDGE TREATMENT AND DISPOSAL

PROBLEM/SOLUTION

8. MISCELLANEOUS AREA INCLUDING BYPASS SYSTEM

PROBLEM/SOLUTION Limestone blinding -- More stringent chemical control has apparently prevented recurrence.

P. DESCRIBE FACTORS WHICH MAY NOT MAKE THIS A REPRESENTATIVE INSTALLATION

Q. DESCRIBE METHODS OF SCRUBBER CONTROL UNDER FLUCTUATING LOAD. IDENTIFY PROBLEMS WITH THIS METHOD AND SOLUTIONS. IDENTIFY METHOD OF pH CONTROL AND LOCATION OF pH PROBES.

As boiler load changes, the air flow thru the scrubber is automatically varied by means of controlling the induced draft fan speed and booster fan dampers. To maintain a constant pressure drop across the venturi portion of the scrubber, the venturi throat automatically opens and closes. To maintain constant gas outlet temperatures, the steam flow to the reheater is also automatically controlled.

pH is manually sampled at two points, the recirculation line and the venturi recirculation tank. An automatic pH sampling system is being installed. Based on the pH readings, the operator manually adjusts the slurry mix.

Mechanical - Misc. Minor. Chemical -- Difficulty in maintaining chemical balance with fluctuating boiler load and sulfur conditions increases the potential for scaling. It is hoped that the automatic chemical control to be installed in the near future will alleviate this situation.

R. COMPUTATION OF FGD SYSTEM AVAILABILITY FACTOR

BOILER RATING OR MAXIMUM CONTINUOUS CAPACITY, MW ______

PERIOD MONTH/YEAR	FLUE GAS DESULFURIZATION MODULES							
	MODULE A		MODULE B		MODULE C		MODULE D	
	DOWN DUE TO		DOWN DUE TO		DOWN DUE TO		DOWN DUE TO	
	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)
June 1973	512	106						
July	677	324						
August	668	110						
September	553	6						
October	738	355						
November	633	201						
December	627	0						
January 1974	743	0						
February	647	0						
March	426	110						
April	684	447						
May	744	693						

Availability factor computation:

1. Divide boiler capacity by the number of modules and obtain MW/module = χ
2. Multiply boiler capacity by number of hours during period = a
3. Add all down times due to module trouble for all modules during period = b
4. Add all down times due to boiler trouble or reduction in electricity demand for all modules during period = c
5. Availability factor = $\frac{[a - \chi\ (b + c)]100}{a - \chi\ c}$ = %

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APPENDIX B

PLANT PHOTOGRAPHS

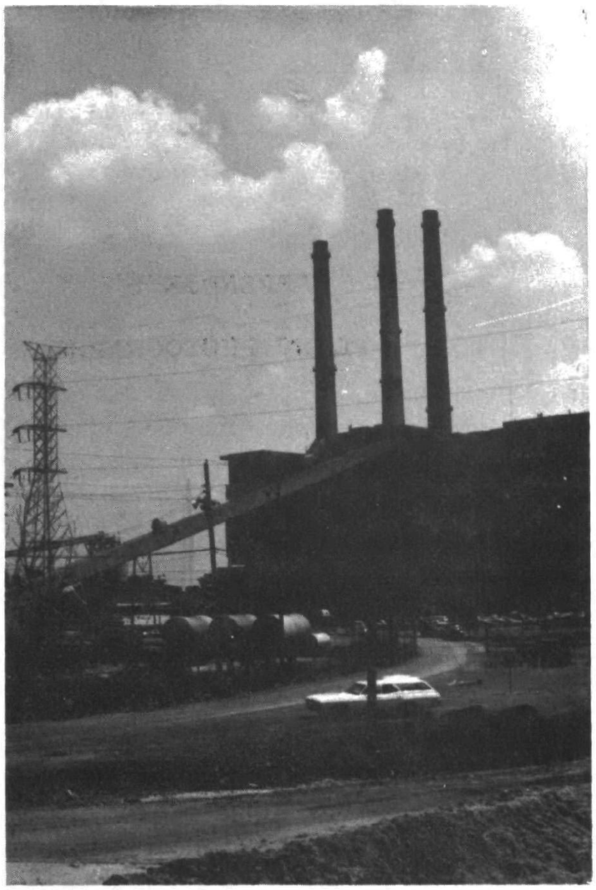

Photo No. 1 General view of the Will County power house showing the coal conveyor (foreground) and the limestone conveyor in the background.

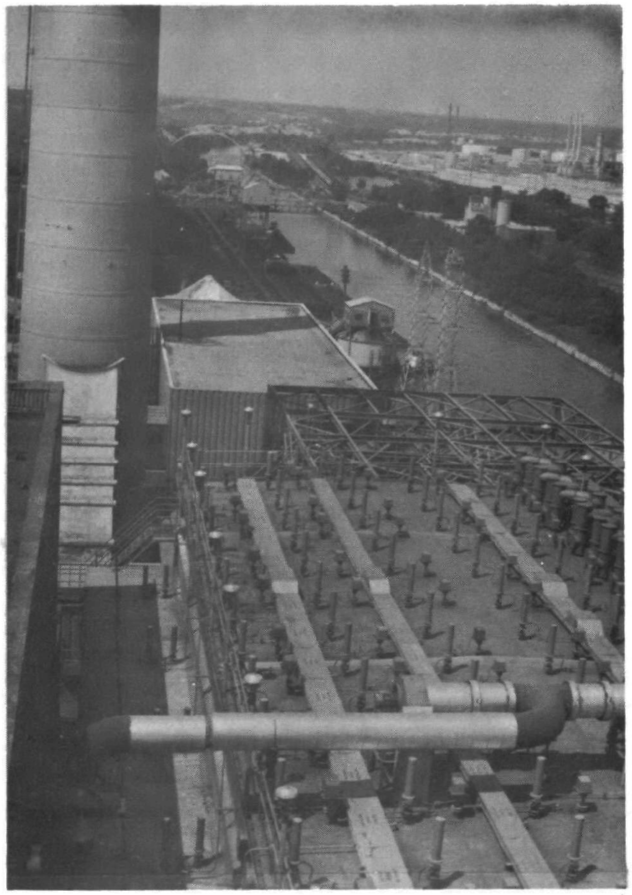

Photo No. 2 View from top of the boiler building looking north towards the ship and sanitary canal. The FGD modules are housed in the building shown behind the electrostatic precipitator structure. The peak of the limestone storage pile can be seen in the background.

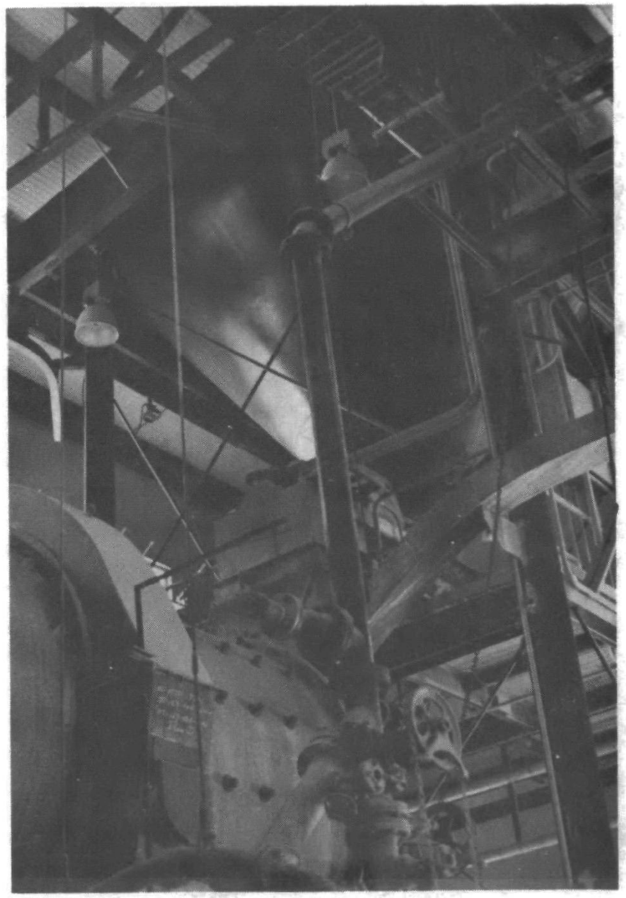

Photo No. 3 View inside the limestone grinding building showing the bottom of the limestone storage silo.

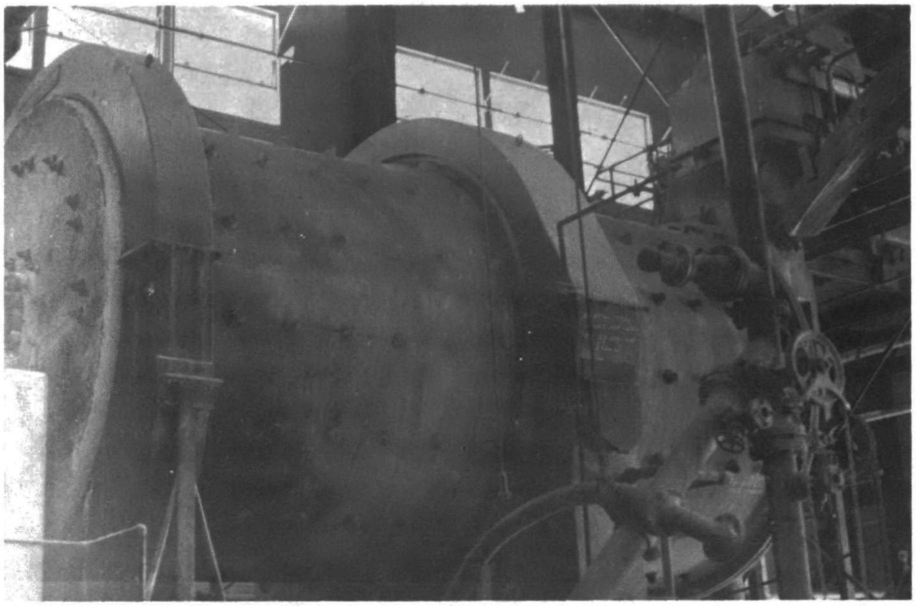

Photo No. 4 One of the two 12-tons/hr limestone ball mills.

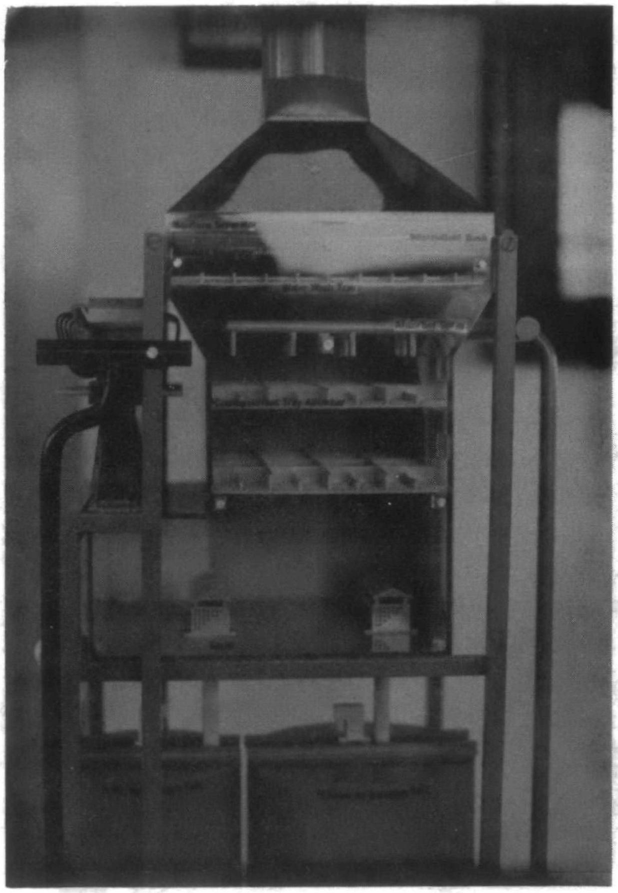

Photo No. 5 Scale model revealing typical arrangements of the module internals. The venturi scrubber on the left and the two-stage scrubber towers to the right. The venturi and scrubber circulation tanks are at ground level.

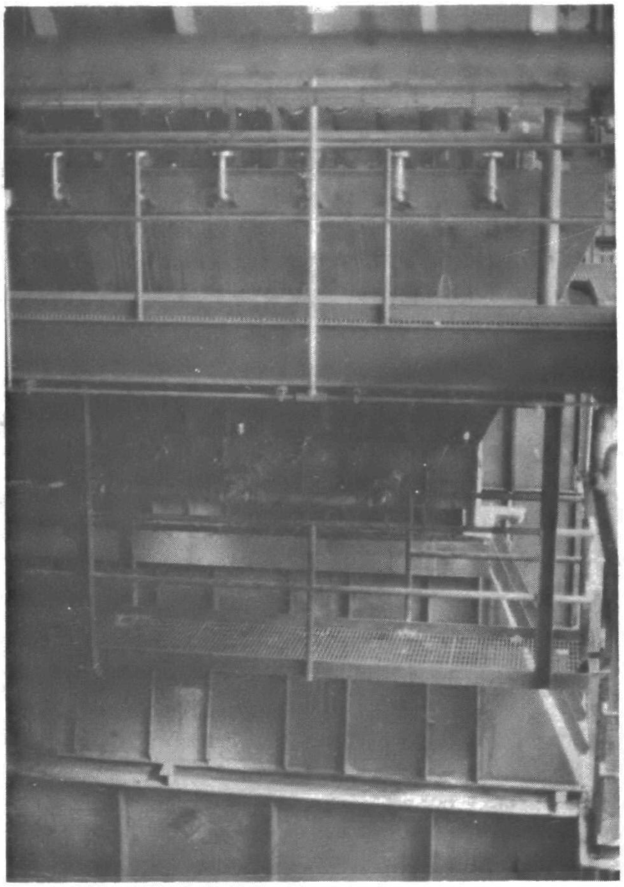

Photo No. 6 Close-up view of a venturi throat showing the motorized mechanism which drives the throat blocks in order to vary the throat's gap. The slurry spray piping is shown at the top.

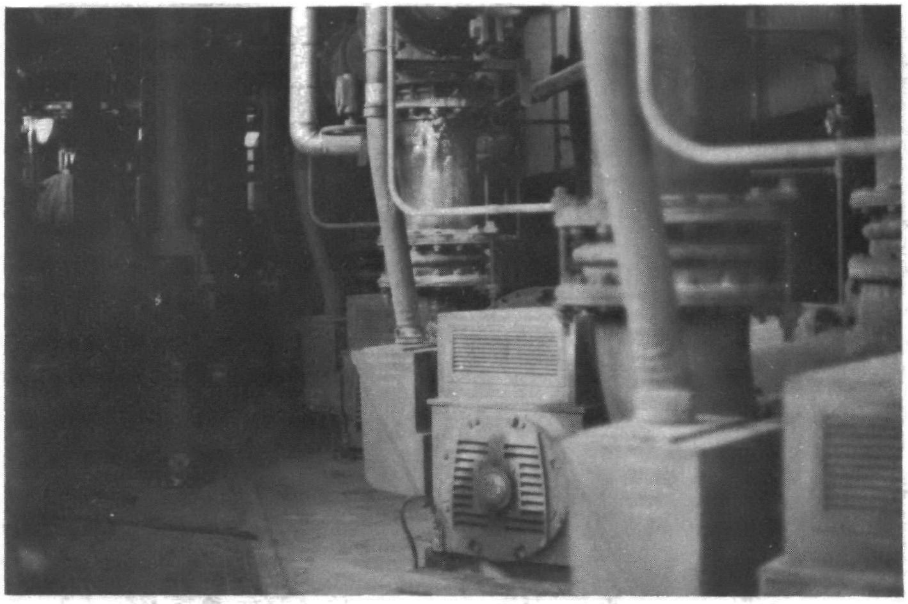

Photo No. 7 Partial view of the slurry circulation pumps. There are three venturi circulation pumps and four scrubber tower circulation pumps serving the modules.

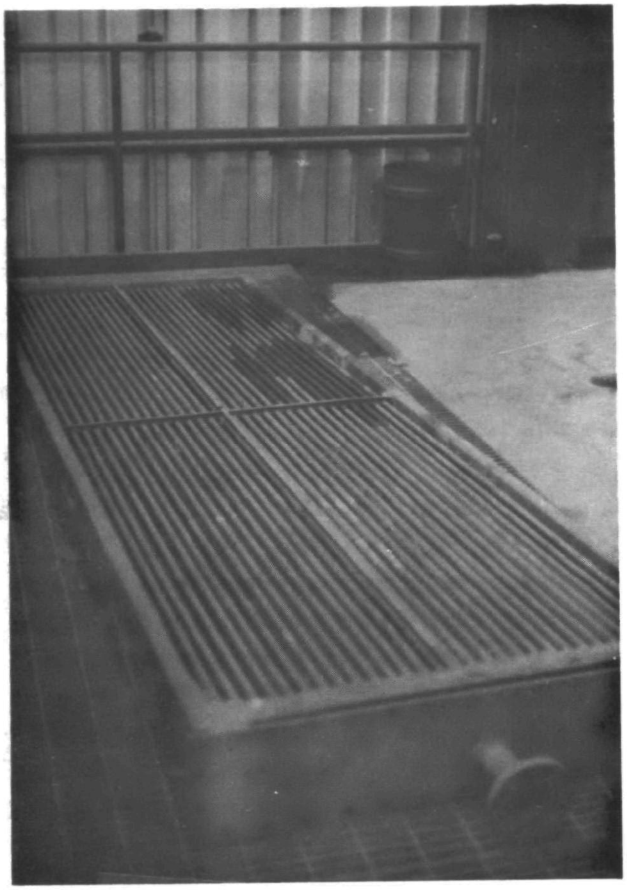

Photo No. 8 Close-up view of a dismantled reheater bundle.

Photo No. 9 View of the booster fan on Module B. Its internals are being examined through the inspection windows.

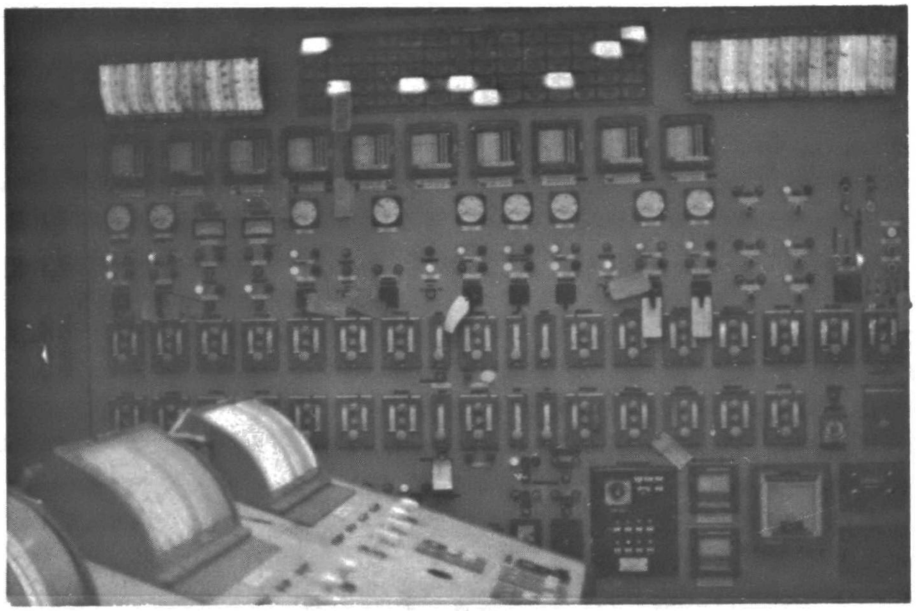

Photo No. 10 The FGD instrument panel which is located in the boiler control room. Some of the important instruments on this panel are the SO_2 inlet and outlet concentrations, pH meters and pump controls.

Photo No. 11 General view of the on-site sludge treatment facilities. The Chicago Fly Ash Company, under contract with Commonwealth Edison, installed and operated the equipment.

Photo No. 12 Top view of the clarifier tank showing the clarified water overflowing the weir to the collection trough on the circumference of the tank.

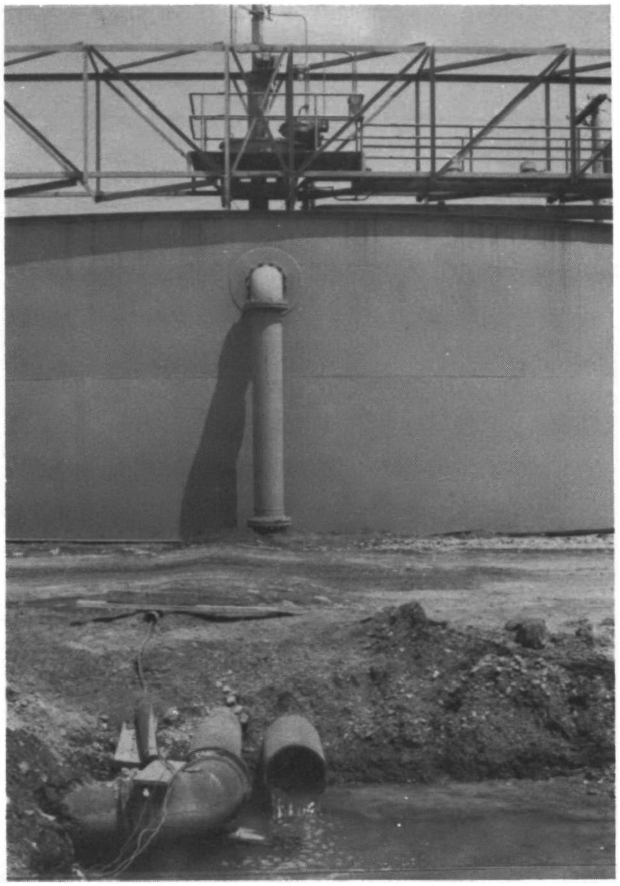

Photo No. 13 Side view of the clarifier tank showing the overflow pipe discharging in the nearby pond. This water is further clarified in the pond and recycled to the FGD system. The underflow pipe is discharged to a holding tank located near the clarifier tank.

Photo No. 14 General view of the pond area. The accumulated silt is periodically excavated and stabilized before it is hauled to an on-site holding basin.

Photo No. 15 View of the sludge stabilization operation. Fly ash and lime stored in the two silos are mixed with the sludge which is either conveyed on the inclined conveyor when cleaning the pond or pumped from the thickener underflow. The three ingredients are then fed to the cement truck. The materials are mixed on the way to the on-site stabilized sludge holding basin.

Photo No. 16 Another view of the sludge stabilization equipment during operation. About 200 pounds of lime and 400 pounds of fly ash are used to stabilize one ton of dry solids in the sludge.

Photo No. 17 The homogenized mixture of stabilized sludge is poured into an on-site sludge holding basin for solidification.

Photo No. 18 The stabilized sludge which solidifies in about one week depending on weather conditions is excavated and piled as shown in this picture and hauled away for disposal in an off-site sanitary landfill.

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

1. REPORT NO. EPA-650/2-75-057-i	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Survey of Flue Gas Desulfurization Systems Will County Station, Commonwealth Edison Co.		5. REPORT DATE October 1975
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Gerald A. Isaacs and Fouad K. Zada		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS PEDCo-Environmental Specialists, Inc. Suite 13, Atkinson Square Cincinnati, Ohio 45246		10. PROGRAM ELEMENT NO. 1AB013; ROAP 21ACX-130
		11. CONTRACT/GRANT NO. 68-02-1321, Task 6i
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 Task Final; 6/74-9/75
		14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

16. ABSTRACT The report gives results of a survey of the flue gas desulfurization (FGD) system at Commonwealth Edison's Will County Station boiler No. 1. The 146 MW (net) boiler was installed in 1955. In 1973 the boiler burned coal with a gross heating value of 9463 Btu/lb and ash and sulfur contents of 10 and 2.1 percent, respectively. The wet limestone FGD system was placed in service on February 23, 1972. It consists of two FGD modules, limestone handling and milling facilities, and a sludge treatment and stabilization unit. Each module consists of a venturi scrubber followed by a two-stage absorption tower. Operating problems were encountered with both modules soon after startup and during initial debugging. Module B was shut down in May 1973 to concentrate on operating Module A. Operating problems have been mainly confined to the demister and reheater units. Additional spray nozzles were installed to keep the demister free of slurry deposits. Estimated capital cost for the Unit 1 FGD system is $115/KW (net), including $13/KW for sludge treatment. Annualized operating cost is estimated to be 12 mills/KWH, based on an assumed boiler capacity factor of 35 percent.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Air Pollution	Coal	Air Pollution Control	13B	21D
Flue Gases	Combustion	Stationary Sources	21B	
Desulfurization	Sludge	Venturi Scrubbers	07A, 07D	
Sulfur Dioxide	Demisters		07B	13A
Limestone	Cost Effectiveness		08G	14A
Scrubbers	Columns (Process Engineering)			
Absorbers (Equipment)				

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS (This Report) Unclassified	21. NO. OF PAGES 71
	20. SECURITY CLASS (This page) Unclassified	22. PRICE

EPA Form 2220-1 (9-73)