EVALUATION OF THE FEASIBILITY OF TOTAL CONVERSION TO COAL FIRING

20-PLANT REPORT

APPENDICES

L - X

PEDCo ENVIRONMENTAL

PEDCo ENVIRONMENTAL
11499 CHESTER ROAD
CINCINNATI, OHIO 45246
(513) 782-4700

EVALUATION OF THE FEASIBILITY OF TOTAL CONVERSION TO COAL FIRING

20-PLANT REPORT

APPENDICES

L - X

Prepared by

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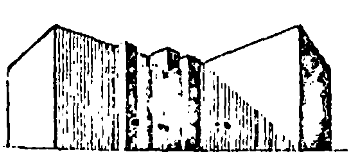
11499 Chester Road
Cincinnati, Ohio 45246

EPA Project Officer: Richard Atherton

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Strategies and Air Standards Division
Pollutant Strategies Branch
Research Triangle Park,
North Carolina 27711

September 24, 1978



CHESTER TOWERS

BRANCH OFFICES

Crown Center
Kansas City Mo.

Professional Village
Chapel Hill, N.C.

APPENDIX L

LOVETT POWER PLANT

CONTENTS

FIGURES

TABLES

TABLES (continued)

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Orange & Rockland Utilities, Inc.
2. MAIN OFFICE: 75 West Route 59, Spring Valley, New York 10977
3. RESPONSIBLE OFFICER: Kenneth B. Field
4. POSITION: Assistant Vice President
5. PLANT NAME: Lovett Generating Station
6. PLANT LOCATION: Tomkins Cove, Town of Stony Point, Rockland County, New York
7. RESPONSIBLE OFFICER AT PLANT LOCATION:
8. POSITION:
9. POWER POOL

DATE INFORMATION GATHERED:

PARTICIPANTS IN MEETING:

B. Baxter, Jr.	Orange and Rockland Utilities, Inc.
K. B. Field	Orange and Rockland Utilities, Inc.
Gerard J. Bogin	Orange and Rockland Utilities, Inc.
C. F. Wilkinson	Orange and Rockland Utilities, Inc.
Barry Tornich	U.S. Environmental Protection Agency
Thomas C. Ponder, Jr.	PEDCo Environmental, Inc.
Alan J. Sutherland	PEDCo Environmental, Inc.
Douglas A. Paul	PEDCo Environmental, Inc.

B. ATMOSPHERIC EMISSIONS	Boiler number 1	2	3	4	5
1. PARTICULATE EMISSIONS[a] LB/MM BTU				.041*	.096*
GRAINS/ACF					
LB/HR (FULL LOAD)					
TONS/YEAR ( )					
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION					
REGULATION & SECTION NO.	NYSDEC			Part 227	Part 227
LB/MM BTU				.10	.10
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a] LB/MM BTU					
LB/HR (FULL LOAD)					
TONS/YEAR ( )					
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT REGULATION & SECTION NO.				NA	NA
LB/MM BTU					
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					

a) Identify whether results are from stack tests or estimates

*NOTE: Analysis based on stack tests burning .3% Sulfur Oil

C. SITE DATA

1. U.T.M. COORDINATES ______________________________

2. ELEVATION ABOVE MEAN SEA LEVEL (FT) ____________________

3. SOIL DATA: BEARING VALUE ______________________________

   PILING NECESSARY ______________________________

4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA

5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE)

6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): ______________

D. BOILER DATA

	Boiler number 1	2	3	4	5
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK					
2. TOTAL HOURS OPERATION (1975)	119.86	108.04	2845.31	6,307.16	8,116.51
3. AVERAGE CAPACITY FACTOR (1975)	0.72	0.72	17.24	36.86	47.68
4. SERVED BY STACK NO.	1	2	3	4	5
5. BOILER MANUFACTURER	B&W+	B&W+	CE°	FW*	B&W+
6. YEAR BOILER PLACED IN SERVICE	1949	1951	1955	1966	1969
7. REMAINING LIFE OF UNIT					
8. GENERATING CAPACITY (MW) RATED	19.1	20	63	202.1	200.6
MAXIMUM CONTINUOUS					
PEAK					
9. FUEL CONSUMPTION: GAS 10^3 FT^3/HR				1500	1528
COAL OR OIL (TPH) OR (GPH) RATED 100%OIL BBL/HR COAL TONS/HR	41.6	41.6	110.0	260	275
MAXIMUM CONTINUOUS	9.6	9.6	25.0	60.0	65.0
PEAK					
10. ACTUAL FUEL CONSUMPTION GAS 10^3 MCF	11.8	12.9	67.9	1402.6	1454.8
COAL (TPY) (1975) 10^3 TONS	-	-	-	-	-
OIL (GPY) (1975) 10^3 BBLS	1.490	1.290	200.78	810.09	1360.5
11. HEAT RATE BTU/KWHR GAS	-	-	-	-	-
COAL	-	-	-	9200	9500
OIL	23,907	24,291	13,235	10,100	10,200
12. WET OR DRY BOTTOM	DRY	DRY	DRY	DRY	DRY
13. FLY ASH REINJECTION (YES OR NO)	NO	NO	NO	NO	NO
14. STACK HGT ABOVE GRADE (FT.)	175	175	175	212	245
15. I.D. OF STACK AT TOP (INCHES)	83	83	150	156	192

Notes:
* FW - FOSTER WHEELER, CORP.
+ B&W - BABCOCK & WILCOX, CO.
° CE - COMBUSTION ENGINEERING

	Boiler number				
	1	2	3	4	5
16. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS					
MANUFACTURER	WEST+	WEST+	PRATT°	NA	NA
TYPE	MCTA	MCTA	MCTA		
EFFICIENCY: DESIGN/ACTUAL (%)	85/-	85/-	85/-		
MASS EMISSION RATE:					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER	NA	NA	NA	COTT*	COTT*
TYPE				E	E
EFFICIENCY: DESIGN/ACTUAL (%)				95/-	95/-
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)					
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)					
17. EXCESS AIR: DESIGN/ACTUAL (%)	25	25	20	20	20

Notes: * COTT - RESEARCH-COTTRELL, INC.
+ WESTERN PRECIPITATION DIVISION
° PRATT DANIEL MECHANICAL PRECIPITATOR

	Boiler number 1	2	3	4	5
18. FLUE GAS RATE (ACFM)					
@ 100% LOAD	110,000	125,000	252,000	648,000	785,000
@ 75% LOAD	61,600	70,000	141,800	362,880	440,980
@ 50% LOAD	27,500	31,200	63,000	162,000	196,280
19. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	335	335	310	300	288
@ 75% LOAD	300	300	300	285	286
@ 50% LOAD	280	280	225	250	267
20. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	49.0	55.7	34.1	85.5	68.5
@ 75% LOAD	27.4	31.2	19.1	38.21	38.3
@ 50% LOAD	12.2	13.9	8.0	17.0	17.3
21. FLY ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD	←		21090		→
DISPOSAL COST ($/TON)					
22. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD					
DISPOSAL COST ($/TON)					
23. EXHAUST DUCT DIMENSIONS @ STACK					
24. ELEVATION OF TIE IN POINT TO STACK					
25. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)					

a) Identify source of values (test or estimate)

Notes:

E. I.D. FAN DATA

	Boiler number				
	1	2	3	4	5
1. MAXIMUM STATIC HEAD (IN. W.G.)	NA	NA	NA	NA	NA
2. WORKING STATIC HEAD (IN. W.G.)	NA	NA	NA	NA	NA

Notes:

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES)
2. YEARS STORAGE (ASH ONLY)
3. DISTANCE FROM STACK (FT.)
4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION
   a.
   b.
   c.
   d.
2. QUANTITY USED BY SEAM AND/OR MINE
   a.
   b.
   c.
   d.
3. ANALYSIS
   HHV (BTU/LB) 13,500 - Design
   S (%)
   ASH (%)
   MOISTURE (%)
4. PPT PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA (1975)

1. TYPE #6 F.O.
2. S CONTENT (%) 0.33
3. ASH CONTENT (%)
4. SPECIFIC GRAVITY
5. HHV (BTU/GAL) 144,533

I. NATURAL GAS HHV (BTU/FT^3) 1026

J. COST DATA

ELECTRICITY

FUEL: COAL GAS OIL

WATER

STEAM

TAXES ON A.P.C. EQUIPMENT: STATE SALES

FEDERAL PROPERTY TAX

K. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE?

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE?

L. ADDITIONAL INFORMATION

F.E.A. LETTER

M. OIL/GAS TO COAL CONVERSION DATA

1. HAS THE BOILER EVER BURNED COAL?

Boiler No.	1	2	3	4	5
Yes or No.	YES	YES	YES	YES	YES

2. SYSTEM AVAILABILITY

2.1 COAL HANDLING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☒ ☐

c. Of the following items which need to be replaced:

	Yes	No
Unloading equipment	☐	☐
Stack Reclaimer	☐	☐
Bunkers	☐	☐
Conveyors	☐	☐
Scales	☐	☐
Coal Storage Area	☐	☐

2.2 FUEL FIRING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☒ ☐

c. Of the following items which need to be replaced:

	Yes	No
Pulverizers or Crushers	☐	☐
Feed Ducts	☐	☐
Fans	☐	☐
Controls	☐	☐

2.3 GAS CLEANING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☒ ☐

c. Of the following items which need to be replaced:

	Yes	No
Electrostatic Precipitator	☐	☐
Cyclones	☐	☐
Fly Ash Handling Equipment	☐	☐
Soot Blowers - Air Compressors	☐	☐
Wall deslaggers	☐	☐

2.4 ASH HANDLING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☒ ☐

c. Of the following items which need to be replaced:

	Yes	No
Bottom Ash Handling	☐	☐
Ash Pond	☐	☐

N. SUPPLEMENTARY CONTROL SYSTEM DATA

1. DOES THE PLANT NOW HAVE A SUPPLEMENTAL CONTROL SYSTEM (SCS)? Yes ☐ No ☐

   If yes, attach a description of the system.

2. IS THE PLANT CAPABLE OF SWITCHING TO LOW SULFUR FUELS? Yes ☐ No ☐

   2.1 Storage capacity for low sulfur fuels (tons, bbls, days)

   2.2 Bunkers available for low sulfur coal storage? Yes ☐ No ☐

   2.3 Handling facilities available for low sulfur fuels Yes ☐ No ☐

   If yes, describe ____________________

   ____

   2.4 Time required to switch fuels and fire the low sulfur fuel in the boiler (hrs)?______

3. IS THE PLANT CAPABLE OF LOAD SHEDDING?

   If yes, discuss ____________________

   ________________________________ Yes ☐ No ☐

4. IS THE PLANT CAPABLE OF LOAD SHIFTING?

   If yes, discuss ____________________

   ________________________________ Yes ☐ No ☐

5. POWER PLANT MONITORING SYSTEM

   5.1 Existing system Yes ☒ No ☐

   a. Air quality instrumentation

	Number	Type
(1) Sulfur Oxides - Continuous		
- Intermittent		
- Static	4	Sulphur Pla'e
(2) Suspended particulates		
- Intermittent		
- Static	4	Dust Collect or

   (3) Other (describe)____________

   b. Meteorological instrumentation

   If yes, describe No

   ____

   c. Is the monitoring data available? Yes ☒ No ☐

   d. Is the monitoring data reduced and analyzed? Yes ☐ No ☒

   e. Provide map of monitoring locations

5.2 Proposed system Yes ☐ No ☐

If yes, describe and provide map ________________

____

a. Air monitoring instrumentation

	Number	Type
(1) Sulfur oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulate		
- Intermittent	______	______
- Static	______	______

(3) Other (describe) ____________

b. Meteorological instrumentation

If yes, describe ______________

____

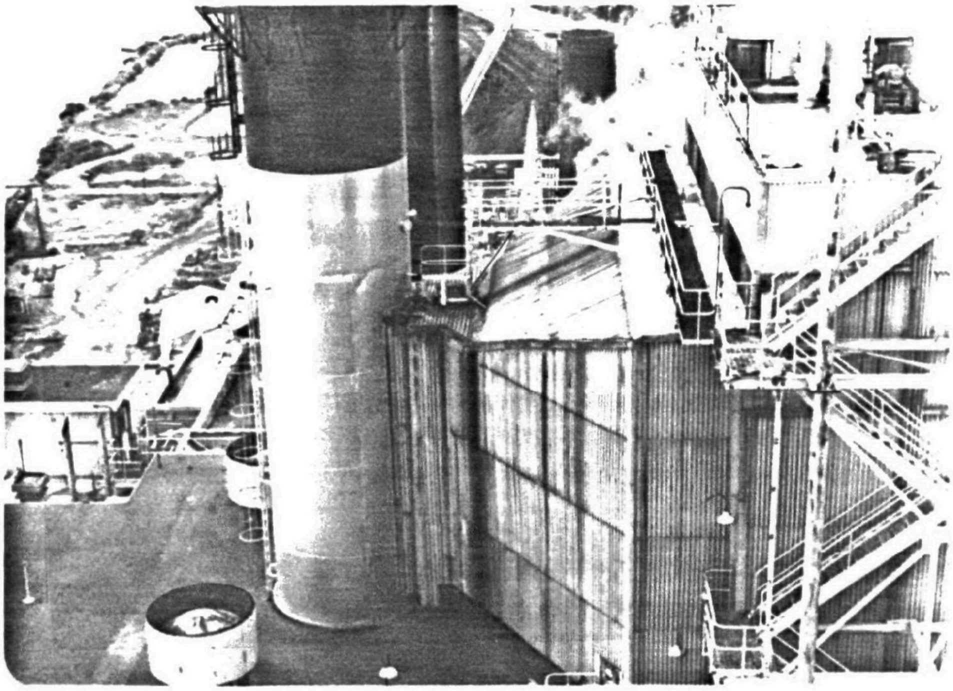


Photo No. 1. View from the roof of the ESP serving Boiler 5 looking at the tie-in of Boiler 4's ESP to the stack.

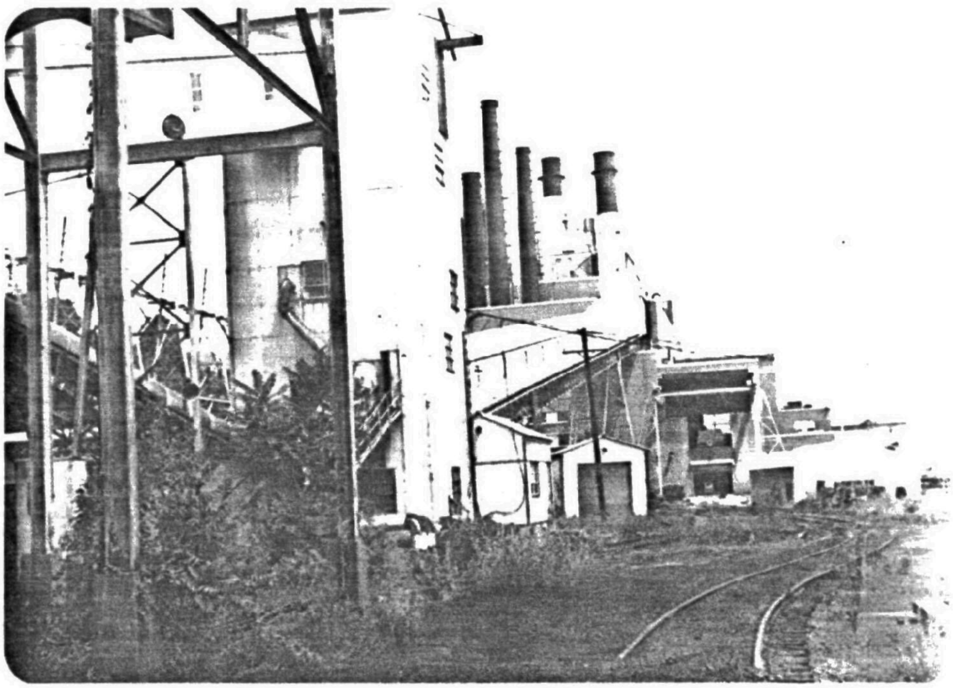


Photo No. 2. View from ground level facing north showing the crusher house and the conveyors. A view of the Lovett plant is in the background.

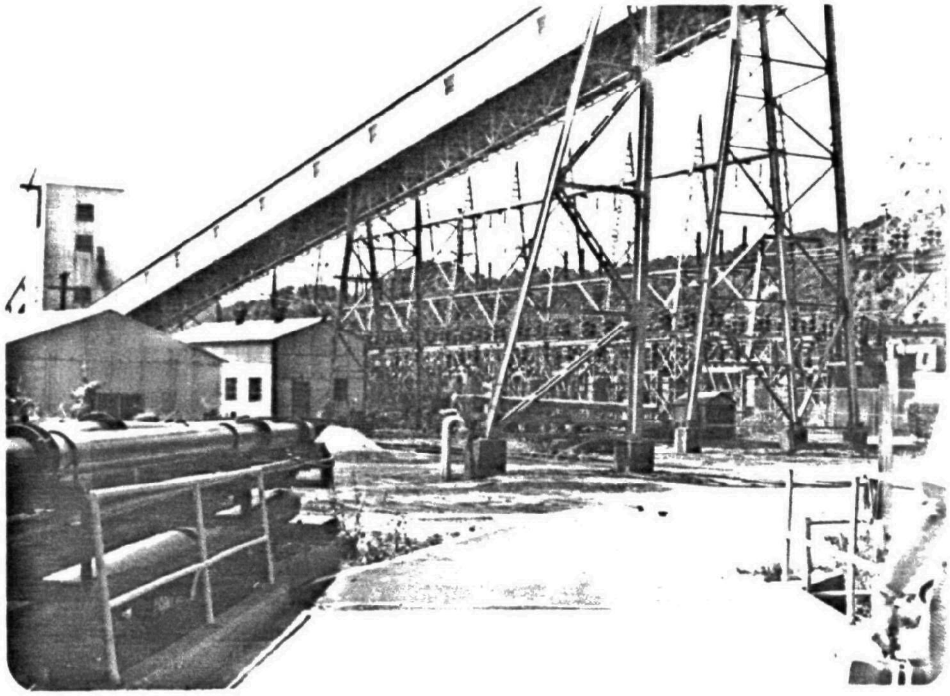


Photo No. 3. View from ground level facing southwest showing electrical substation.

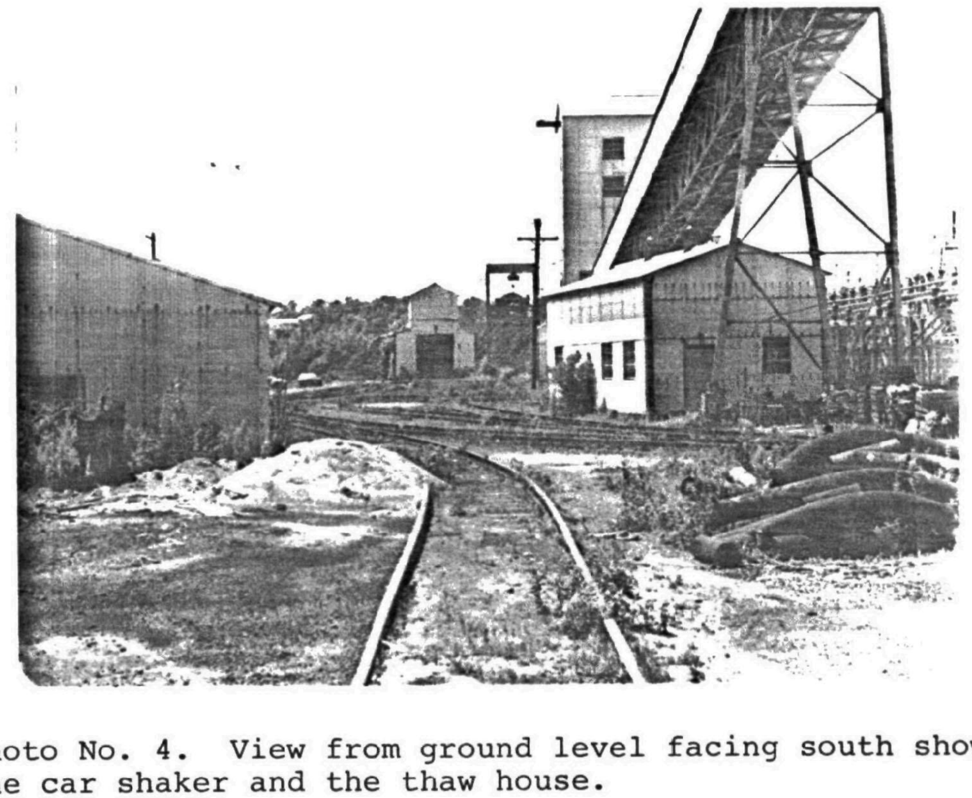


Photo No. 4. View from ground level facing south showing the car shaker and the thaw house.

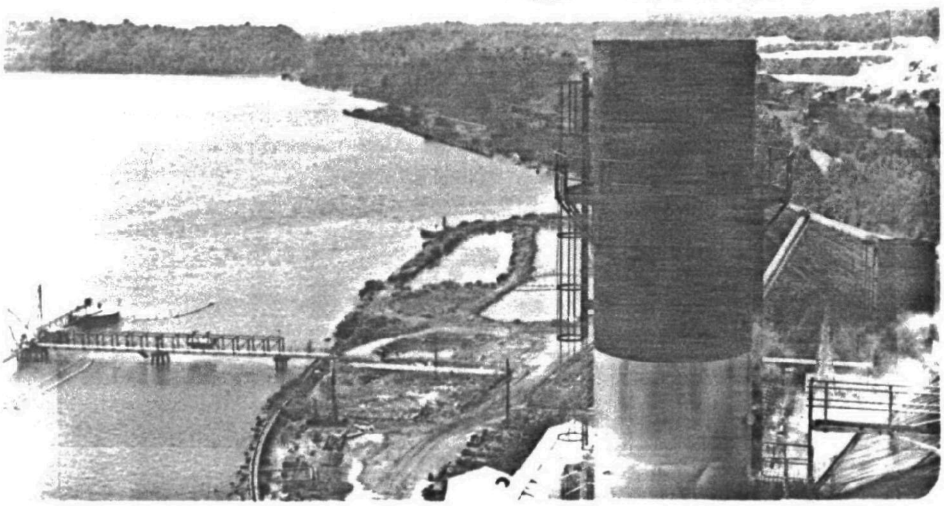


Photo No. 5. View from the roof of the ESP serving Boiler 5 facing south showing sludge ponds and stack 4. The Hudson River, the rock quarry, and the surrounding area are shown in the background.

Photo No. 6. View from the roof of the ESP serving Boiler 5 facing north showing the parking lot and the warehouse.

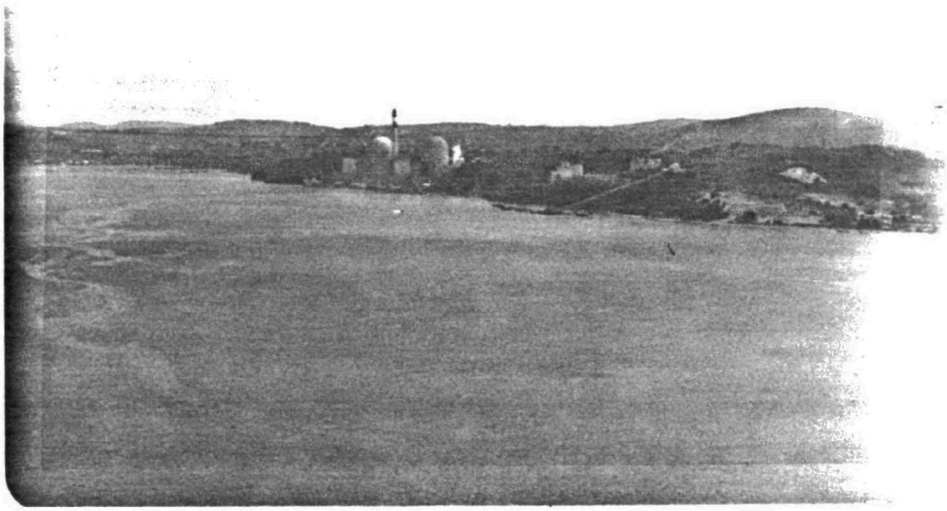


Photo No. 7. View from the roof of the ESP serving Boiler 5 facing northeast showing the Hudson River, Indian Power Plant, and the surrounding area.

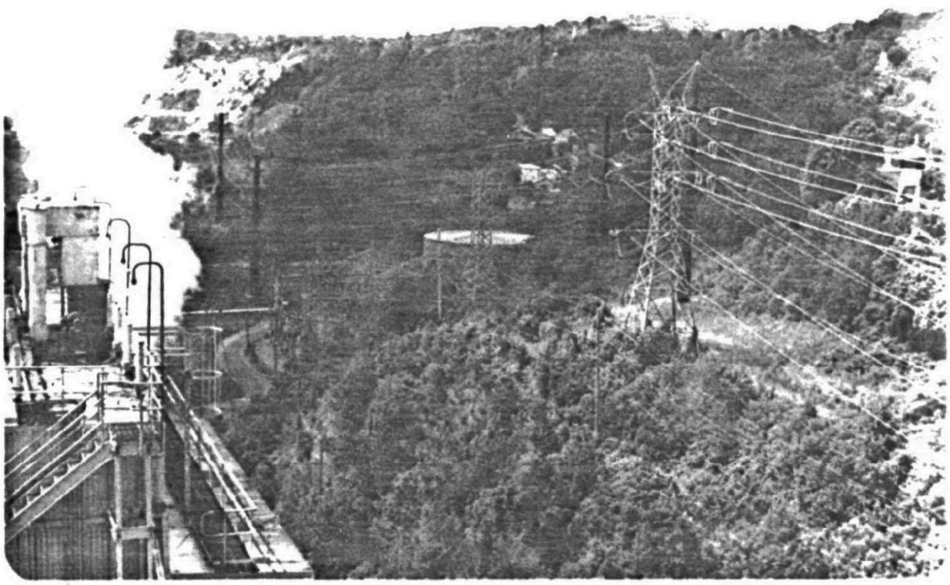


Photo No. 8. View from the roof of the ESP serving Boiler 5 facing southwest showing the residual fuel oil hold tank. The rock quarry and the surrounding area are in the background.

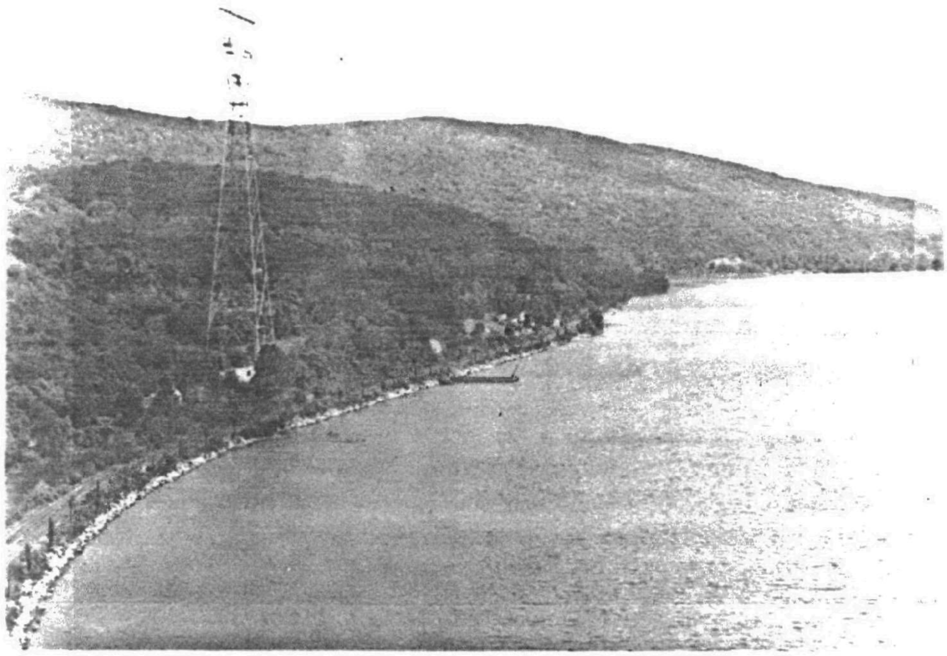


Photo No. 9. View from the roof of the ESP serving Boiler 5 facing north showing the Hudson River and the surrounding area.

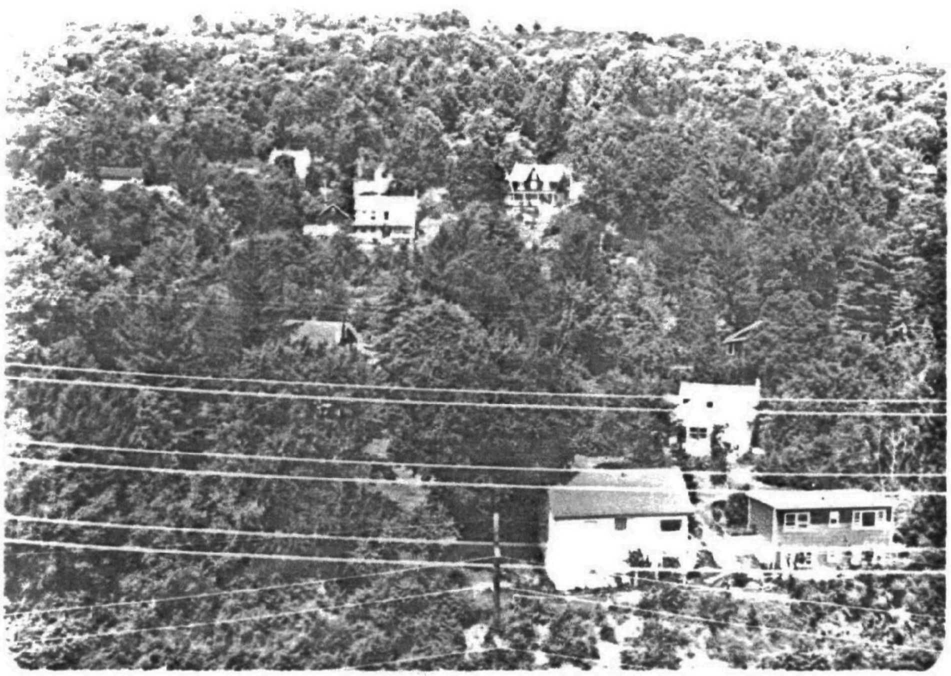


Photo No. 10. View from the roof of the ESP serving Boiler 5 facing west showing the surrounding area.

TABLE L-1. ESTIMATED CAPITAL COST OF A SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILERS 3, 4, AND 5 AT THE LOVETT POWER PLANT (1978)

Direct Costs			
A.	Soda Ash Preparation		
	Storage silos		$ 55,000
	Vibrating feeders		6,000
	Storage tanks		26,000
	Agitators		26,000
	Pumps and motors		2,000
		Total A =	$ 115,000
B.	SO_2 Scrubbing		
	Absorbers		$ 10,728,000
	Fans and motors		1,186,000
	Pumps and motors		314,000
	Reheaters		1,875,000
	Soot blowers		1,630,000
	Ducting		2,711,000
	Valves		376,000
		Total B =	$ 18,820,000
C.	Purge Treatment		
	Refrigeration unit		$ 306,000
	Heat exchangers		46,000
	Tanks		60,000
	Dryer		27,000
	Elevator		15,000
	Pumps and motors		252,000
	Centrifuge		611,000
	Crystallizer		733,000
	Storage silo		55,000
	Feeder		6,000
		Total C =	$ 2,111,000

(continued)

TABLE L-1 (continued)

D.	Regeneration	
	Pumps and motors	$ 223,000
	Evaporators and reboilers	2,867,000
	Heat exchangers	374,000
	Tanks	51,000
	Stripper	115,000
	Blower	122,000
	Total D =	$ 3,752,000
E.	Particulate Removal	
	Venturi scrubber	$ 4,710,000
	Tanks	140,000
	Pumps and motors	550,000
	Total E =	$ 5,400,000
	Total direct costs = A + B + C + D + E = F =	$ 30,198,000
Indirect Costs		
	Interest during construction	$ 3,020,000
	Field labor and expenses	3,020,000
	Contractor's fee and expenses	1,510,000
	Engineering	3,020,000
	Freight	378,000
	Offsite	906,000
	Taxes	000
	Spares	151,000
	Allowance for shakedown	1,510,000
	Acid plant	1,476,000
	Total indirect costs G =	$ 14,991,000
	Contingency H =	9,038,000
	Total = F + G + H =	$ 54,227,000
	Coal conversion costs	3,424,000
	Grand total	$ 57,651,000
	$/kW	123.79

TABLE L-2. ESTIMATED ANNUAL OPERATING COST OF A SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILERS 3, 4, AND 5 AT THE LOVETT POWER PLANT (1978)

	Quantity	Unit Cost	Annual Cost
Raw Materials			
Soda ash	0.45 ton/h	\$90.3/ton	\$ 139,000
Utilities			
Process water	2,068.3 gal/min	0.069 \$/10^3 gal	29,000
Cooling water	8.8 x 10^3 gal/min	0.017 \$/10^3 gal	31,000
Electricity	10,015 kW	55.7 mills/kWh	1,873,000
Reheat steam	71.2 10^6 Btu/h	2.835 \$/10^6 Btu	679,000
Process steam	126.7 10^6 Btu/h	2.835 \$/10^6 Btu	1,209,000
Operation Labor			
Direct labor	4 men/day	\$10.67/man-hour	374,000
Supervision	15% of direct labor		56,000
Maintenance			
Labor and materials	4% of fixed investment		2,169,000
Supplies	15% of labor and materials		325,000
Overhead			
Plant	50% of operating and maintenance		1,462,000
Payroll	20% of operating labor		86,000
Fixed Costs			
Depreciation	(5.00%)		
Interim replacement	(0.35%)		
Insurance	(0.30%)		
Taxes	(4.00%), Σ = 20.85% of fixed investment		
Capital cost	(11.20%)		
Total fixed cost			\$ 11,306,000
Total cost			\$ 19,738,000
Credits (byproducts)			
Sulfuric acid	6.30 tons/h	\$65.24/ton	(1,382,000)
Na_2SO_4	0.45 ton/h	\$79.34/ton	(122,000)
Total byproduct credits			\$ (1,504,000)
Fuel credit			(11,222,000)
Net annual cost			\$ 7,012,000
Mills/kWh			4.44

Table L-3. RETROFIT EQUIPMENT AND FACILITIES FOR THE SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILERS 3, 4, AND 5 AT THE LOVETT POWER PLANT

Module Description	Number Required	Size/Capacity
Absorbers	5	93.4 MW capacity unit
Flue gas fans	5	Scaled to train size
Na_2CO_3 storage	1	324 tons (30-day storage)
Na_2CO_3 preparation	1	900 lb/hr, Na_2CO_3
SO_2 regeneration	1	6746 lb/hr, SO_2
Purge treatment	1	900 lb/hr, Na_2SO_4
Sulfuric acid plant	1	23.5 tons/day, H_2SO_4

Table L-4. RETROFIT EQUIPMENT DIMENSIONS REQUIRED FOR THE SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILERS 3, 4, AND 5 AT THE LOVETT POWER PLANT

Item	Number required	Dimensions, ft
Na_2CO_3 storage	1	13 diam x 26 high
Absorber feed surge tank	1	24 diam x 24 high
Turbulent contact absorbers	5	45 high x 15 wide x 39.4 long
Regeneration plant	1	34 wide x 130 long
Purge treatment plant	1	41 wide x 170 long
Acid plant	1	57 wide x 124 long

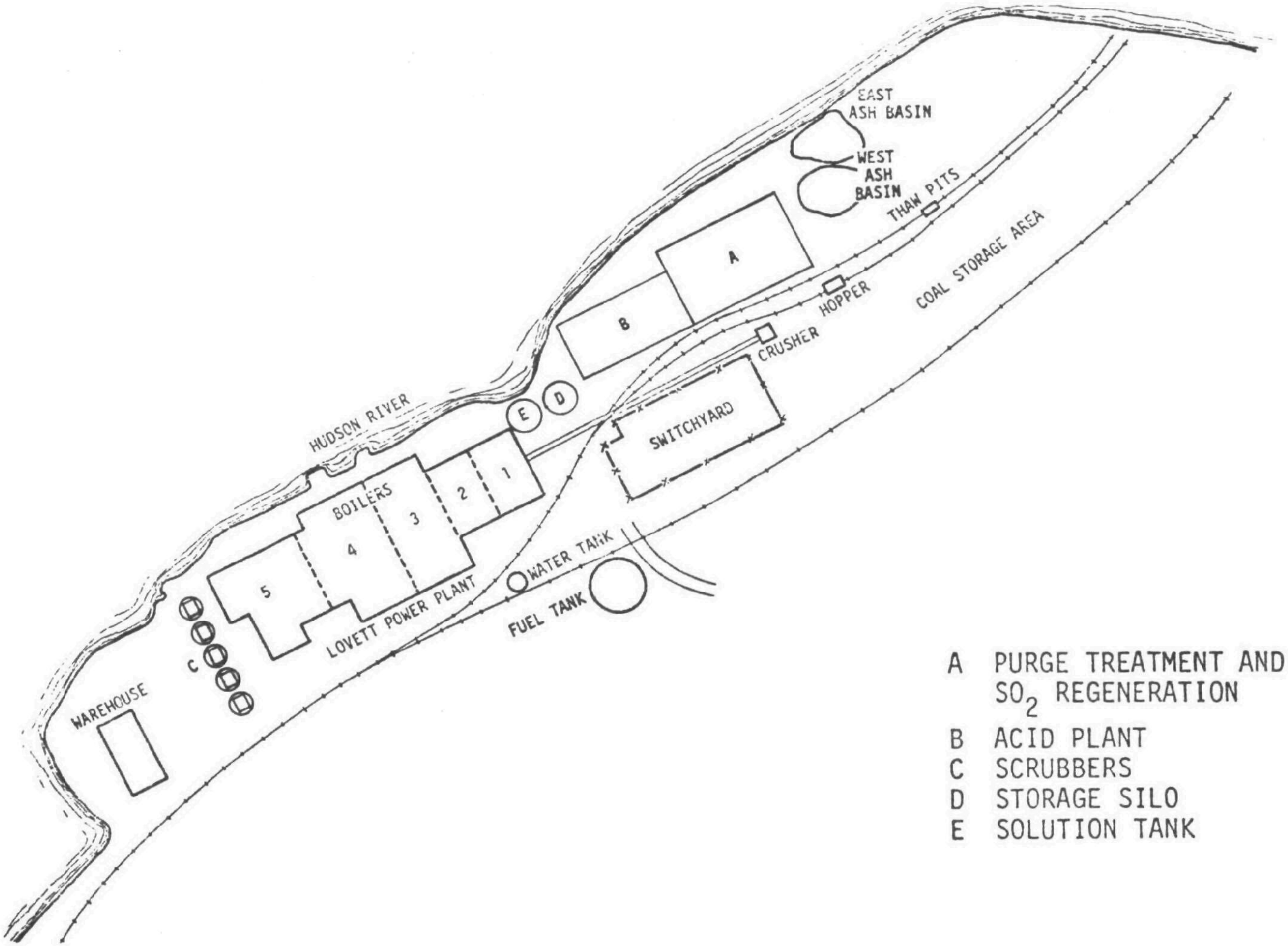


Figure L-1. Site plan showing possible location of major components for the sodium solution regenerable system for Boilers 3, 4 and 5 at the Lovett power plant.

TABLE L-5. ESTIMATED CAPITAL COST OF A LIMESTONE SCRUBBING SYSTEM FOR BOILERS 3, 4, AND 5 AT THE LOVETT POWER PLANT (1978)

Direct Cost			
A.	Limestone Preparation		
	Conveyors		$ 410,000
	Storage silo		76,000
	Ball mills		642,000
	Pumps and motors		128,000
	Storage tanks		93,000
		Total A =	$ 1,349,000
B.	Scrubbing		
	Absorbers		$ 9,950,000
	Fans and motors		1,519,000
	Pumps and motors		786,000
	Tanks		611,000
	Reheaters		2,161,000
	Soot blowers		652,000
	Ducting and valves		3,242,000
		Total B =	$18,921,000
C.	Sludge Disposal		
	Clarifiers		$ 197,000
	Vacuum filters		299,000
	Tanks and mixers		8,000
	Fixation chemical storage		26,000
	Pumps and motors		54,000
	Sludge pond		1,347,000
	Mobile equipment		64,000
		Total C =	$ 1,995,000

(continued)

TABLE L-5 (continued)

D.	Particulate Removal	
	Venturi scrubber	$ 5,428,000
	Tanks	165,000
	Pumps and motors	225,000
	Total D =	$ 5,818,000
	Total direct costs = A + B + C + D = E =	$ 28,083,000
Indirect Costs		
	Interest during construction	$ 2,808,000
	Field overhead	2,808,000
	Contractor's fee and expenses	1,404,000
	Engineering	2,808,000
	Freight	351,000
	Offsite	842,000
	Taxes	000
	Spares	140,000
	Allowance for shakedown	1,404,000
	Total indirect costs F =	$ 12,565,000
	Contingency G =	8,130,000
	Total = E + F + G =	$ 48,778,000
	Coal conversion costs	3,424,000
	Grand total	$ 52,202,000
	$/kW	112.09

TABLE L-6. ESTIMATED ANNUAL OPERATING COSTS OF A LIMESTONE SCRUBBING SYSTEM FOR BOILERS 3, 4, AND 5 AT THE LOVETT POWER PLANT (1978)

	Quantity	Unit Cost	Annual Cost
Raw Materials			
Limestone	8.8 tons/h	\$16.81/ton	\$ 498,000
Fixation chemicals	21.8 tons/h	\$ 2.20/ton	162,000
Utilities			
Water	174.1 gal/min	0.068 $\$/10^3$ gal	2,000
Electricity	9395 kW	55.6 mills/kWh	1,758,000
Fuel for reheat	82.0×10^6 Btu/h	2.835 $\$/10^6$ Btu	782,000
Operating Labor			
Direct labor	4 men/day	\$10.67/man-hour	374,000
Supervision	15% of direct labor		56,000
Maintenance			
Labor and materials	4% of fixed investment		1,951,000
Supplies	15% of labor and material		293,000
Overhead			
Plant	50% of operation and maintenance		1,337,000
Payroll	20% of operating labor		86,000
Trucking			
Bottom/fly ash and sludge removal			3,243,000
Fixed Costs			
Depreciation	(5.00%)		
Interim replacement	(0.35%), Σ = 20.85% of fixed investment		
Insurance	(0.30%)		
Taxes	(4.00%)		
Capital costs	(11.20%)		
Total fixed charges			10,170,000
Total costs			\$ 20,712,000
Fuel credit			(11,222,000)
Net annual cost			\$ 9,490,000
Mills/kWh			6.01

Table L-7. RETROFIT EQUIPMENT AND FACILITIES REQUIRED FOR THE LIMESTONE SCRUBBING SYSTEM FOR BOILERS 3, 4, AND 5 AT THE LOVETT POWER PLANT

Module Description	Number Required	Size/Capacity
Limestone storage	1	6336 tons (30 day storage)
Limestone slurry	1	8.8 ton/hr limestone
Turbulent contact absorbers	5	93.4 MW capacity units
Flue gas fans	5	Scaled to train size

Table L-8. RETROFIT EQUIPMENT DIMENSIONS REQUIRED FOR THE LIMESTONE SCRUBBING SYSTEM FOR BOILERS 3, 4, AND 5 AT THE LOVETT POWER PLANT

Item	Number Required	Dimensions, ft
Limestone storage pile	1	115 W x 117 L
Limestone silos	3	14 diam x 31 height
Limestone slurry tanks	1	45 diam x 20 height
Ball mill building	1	30 W x 30 L
Turbulent contact absorbers	5	45 height x 15 width x 29 length
Clarifiers	2	49 diam x 20 height
Vacuum filter building	1	30 W x 30 L

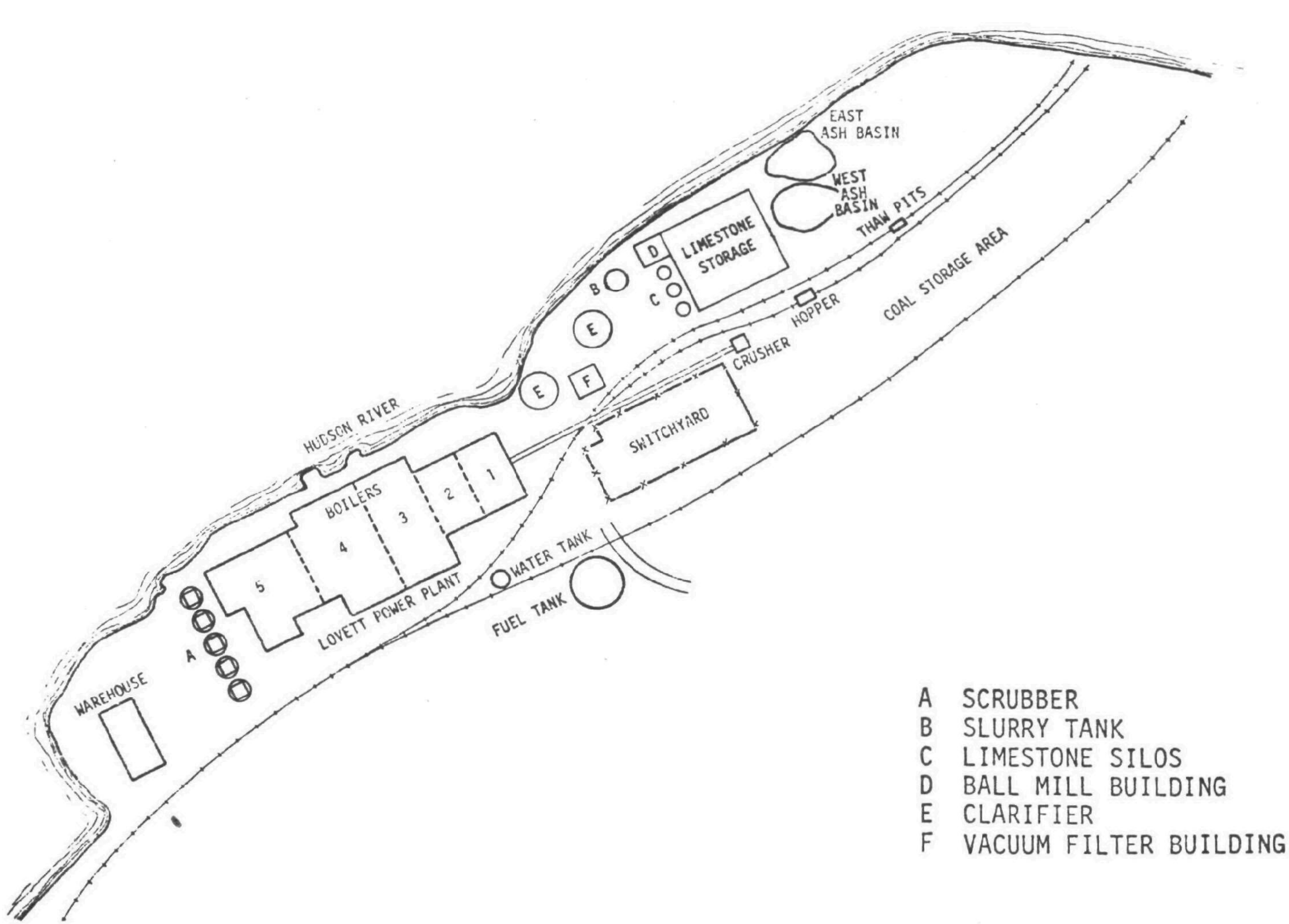


Figure L-2. Site plan showing the possible locations of major components for the limestone system for Boilers 3, 4, and 5 at the Lovett power plant.

TABLE L-9. ESTIMATED CAPITAL COST OF ELECTROSTATIC PRECIPITATORS FOR BOILERS 3, 4, AND 5 AT THE LOVETT POWER PLANT (1978)

Direct Costs		
ESP		$ 9,701,000
Ash handling		1,563,000
Ducting		1,171,000
	Total direct costs	$ 12,435,000
Indirect Costs		
Interest during construction	8% of direct costs	$ 995,000
Contractor fee	10% of direct costs	1,244,000
Engineering	6% of direct costs	746,000
Freight	1.25% of direct costs	155,000
Offsite	3% of direct costs	373,000
Taxes	0% of direct costs	000
Spares	1% of direct costs	124,000
Allowance for shakedown	3% of direct costs	373,000
Total indirect costs		$ 4,010,000
Contingency		3,289,000
Total		$ 19,734,000
Coal conversion costs		3,424,000
Grand total		$ 23,158,000
$/kW		49.73

TABLE L-10. ESTIMATED ANNUAL OPERATING COST OF ELECTROSTATIC PRECIPITATORS FOR BOILERS 3, 4, AND 5 AT THE LOVETT POWER PLANT (1978)

Utilities	Quantity	Unit Cost	Annual Costs
Electricity	1851 kW	55.7 mills/kWh	$ 346,000
Water	9784 x 10^3/gal	$0.01/$10^3$ gal	1,000
Operating Labor			
Direct labor	0.5 man/shift	$10.67/man-hour	139,000
Supervision	15% of direct labor		21,000
Maintenance			
Labor and materials	2% of fixed investment		395,000
Supplies	15% of labor and materials		59,000
Overhead			
Plant	50% of operating and maintenance		307,000
Payroll	20% of operating labor		32,000
Trucking			
Bottom/fly ash removal			1,856,000
Fixed costs			
Depreciation	(4.00%)		
Interim replacement	(0.35%), Σ = 19.85% of fixed investment		
Insurance	(0.30%)		
Taxes	(4.00%)		
Capital cost	(11.20%)		
Total fixed cost			3,917,000
Total cost			$ 7,073,000
Fuel credit			(11,222,000)
Net annual credit			$ (4,149,000)
Mills/kWh			(2.63)

Table L-11. ELECTROSTATIC PRECIPITATOR DESIGN VALUES FOR BOILERS 3 AND 4 AT THE LOVETT POWER PLANT

Design Parameter	Value	
	3	4
Collection efficiency, % (Overall)	98.66	98.66
Specific collecting area, ft^2/1000 acfm	449	399
Total collecting area, ft^2	113,200	258,700
Superficial velocity, fps	4.0	4.0
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	30 x 35 x 43	27 x 100 x 37

Table L-11(Continued). ELECTROSTATIC PRECIPITATOR DESIGN VALUES FOR BOILER 5 AT THE LOVETT POWER PLANT (1976)

Design Parameter	Value
	5
Collection efficiency, % (Overall)	98.66
Specific collecting area, ft^2/1000 acfm	312
Total collecting area, ft^2	245,300
Superficial velocity, fps	4.0
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	21 x 156 x 28

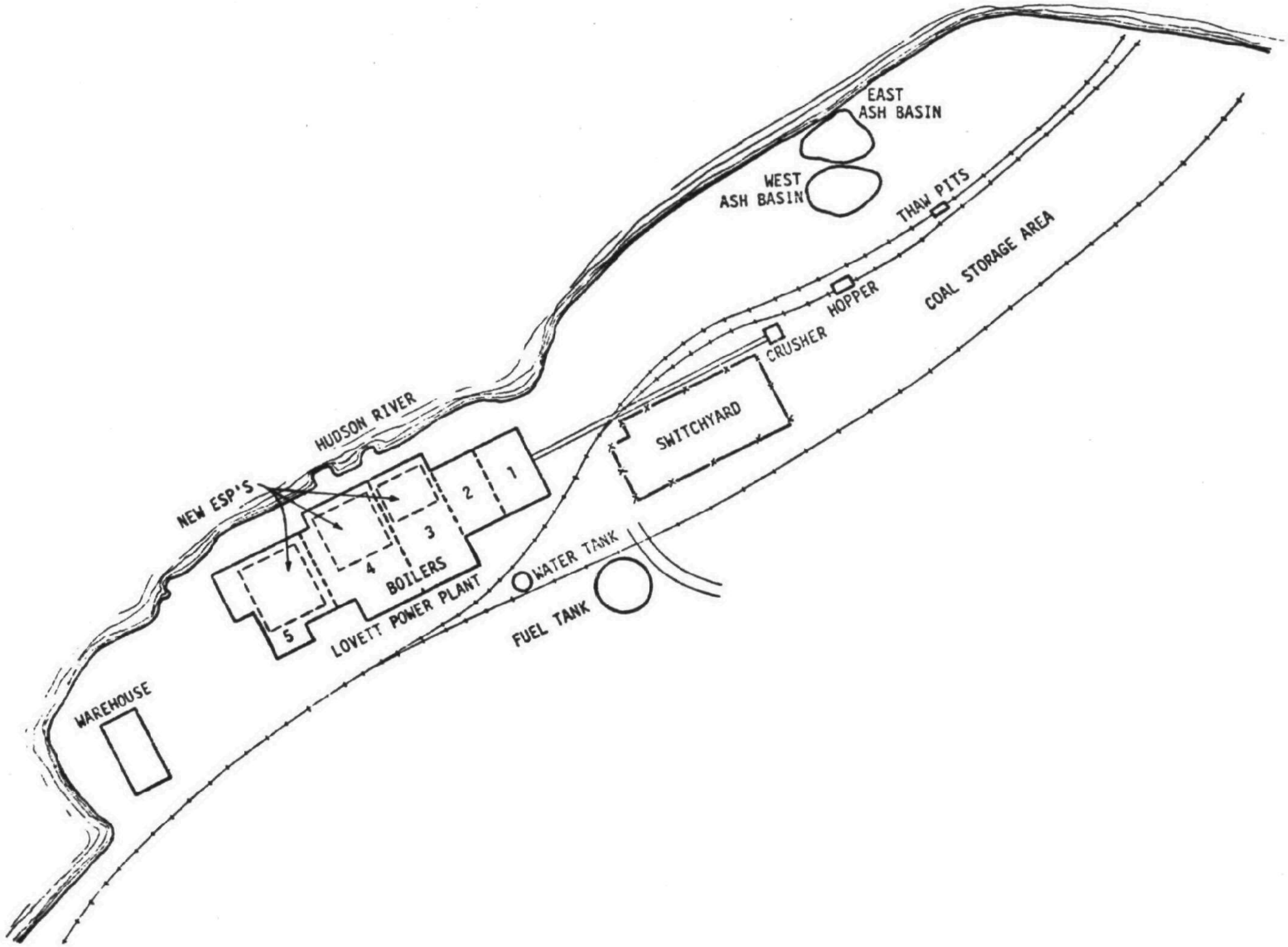


Figure L-3. Site plan showing possible locations of new ESP's for Boilers 3, 4, and 5 at the Lovett power plant.

APPENDIX M

MUSTANG POWER PLANT

CONTENTS

FIGURES

TABLES

TABLES (continued)

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Oklahoma Gas and Electric Company
2. MAIN OFFICE: P.O. Box 321, Oklahoma City, Oklahoma 73101
3. RESPONSIBLE OFFICER: G. L. Gibbons
4. POSITION: Vice President
5. PLANT NAME: Mustang
6. PLANT LOCATION: Oklahoma, Canadian Oklahoma City 73127
7. RESPONSIBLE OFFICER AT PLANT LOCATION: K.A. Ketchersid
8. POSITION: Plant Superintendant
9. POWER POOL Southwest Power Pool

DATE INFORMATION GATHERED: April 26, 1976

PARTICIPANTS IN MEETING:
George L. Gibbons Oklahoma Gas & Electric Co.
John D. Graham Oklahoma Gas & Electric Co.
V. T. Huckleberry Oklahoma Gas & Electric Co.
O. Wayne Beasley Oklahoma Gas & Electric Co.
Jerry Gouett Oklahoma Gas & Electric Co.
Jim Pollard Oklahoma Gas & Electric Co.
Pat Ryan Oklahoma Gas & Electric Co.
Cris Caenepeel EPA - OAQPS
Thomas C. Ponder, Jr. PEDCo Environmental, Inc.
N. David Noe PEDCo Environmental, Inc.
Richard T. Price PEDCo Environmental, Inc.

B. ATMOSPHERIC EMISSIONS	Boiler number 1	2			
1. PARTICULATE EMISSIONS[a] (A.P. 42)					
LB/MM BTU Gas-Firing Calc.	.014	.014			
GRAINS/ACF					
LB/HR (FULL LOAD)					
TONS/YEAR (1975) Calc.	19	19			
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION	AQCR	184			
REGULATION & SECTION NO.	Section 6.2, Figure I				
LB/MM BTU	0.25	0.25			
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a] (A.P. 42)					
LB/MM BTU Gas-Firing Calc.	.0006	.0006			
LB/HR (FULL LOAD)					
TONS/YEAR (1975) Calc.	< 1	< 1			
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.	Section 16.21				
LB/MM BTU	Ambient SO_2 Standard				
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO. *					
LB/MM BTU	*	*			

a) Identify whether results are from stack tests or estimates

*According to the State of Oklahom The Mustang plant must comply with Federal NSPS (i.e. 1.2 lbs/mmBtu SO_2) if converted to coal-firing.

C. SITE DATA

1. U.T.M. COORDINATES N 25° 33' 19" W 97° 40' 27"
2. ELEVATION ABOVE MEAN SEA LEVEL (FT) 1237.5'
3. SOIL DATA: BEARING VALUE ______

   PILING NECESSARY Had to pile 65'
4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA
5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE) 1363'4"
6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): 39' 11"

D. BOILER DATA

	Boiler number 1	Boiler number 2			
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK					
2. TOTAL HOURS OPERATION (1975)	7132.7	7868.1			
3. AVERAGE CAPACITY FACTOR (19 75)	38.6	44.2			
4. SERVED BY STACK NO.	1	2			
5. BOILER MANUFACTURER	B & W*	B & W*			
6. YEAR BOILER PLACED IN SERVICE	1950	1951			
7. REMAINING LIFE OF UNIT					
8. GENERATING CAPACITY (MW) RATED					
MAXIMUM CONTINUOUS Gas	60	58			
PEAK					
9. FUEL CONSUMPTION:					
COAL ~~OR-OIL~~ (TPH) OR (GPH) RATED tons/hour MAXIMUM CONTINUOUS	27	27			
PEAK					
10. ACTUAL FUEL CONSUMPTION Gas (1000MCF)	2,575	2,710			
COAL (TPY) (19 75)	None	None			
OIL (GPY) (19 75)	None	None			
11. WET OR DRY BOTTOM	Dry	Dry			
12. FLY ASH REINJECTION (YES OR NO)	No	No			
13. STACK HGT ABOVE GRADE (FT.)	250	250			
14. I.D. OF STACK AT TOP (INCHES)	126	126			

Notes: * B & W - The Babcock & Wilcox Co.

	Boiler number				
	1	2			
15. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS					
MANUFACTURER	NA	NA			
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE: (GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER	NA	NA			
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)					
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)					
16. EXCESS AIR: DESIGN/ACTUAL (%)	16/	16/			

Notes:

	Boiler number				
	1	2			
17. FLUE GAS RATE (ACFM)					
@ 100% LOAD	134,115	134,115			
@ 75% LOAD	115,000	115,000			
@ 50% LOAD	89,000	89,000			
18. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	290	290			
@ 75% LOAD	273	273			
@ 50% LOAD	247	247			
19. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	25.8	25.8			
@ 75% LOAD	22.2	22.2			
@ 50% LOAD	17.1	17.1			
20. FLY ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD					
DISPOSAL COST ($/TON)					
21. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD					
DISPOSAL COST ($/TON)					
22. EXHAUST DUCT DIMENSIONS @ STACK					
23. ELEVATION OF TIE IN POINT TO STACK					
24. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)					

a) Identify source of values (test or estimate)

Notes:

E. I.D. FAN DATA

	Boiler number				
	1	2			
1. MAXIMUM STATIC HEAD (IN. W.C.)	14	14			
2. WORKING STATIC HEAD (IN. W.C.)	8.2	8.2			

Notes: No Controls Presently

Would Need Extra Capacity if ESP Added

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES)

2. YEARS STORAGE (ASH ONLY)

3. DISTANCE FROM STACK (FT.)

4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION

a.

b.

c.

d.

2. QUANTITY USED BY SEAM AND/OR MINE

a.

b.

c.

d.

3. ANALYSIS

GHV (BTU/LB)	12,971
S (%)	1.3
ASH (%)	10.0
MOISTURE (%)	10.5

4. PPT PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA

1. TYPE

2. S CONTENT (%) .4

3. ASH CONTENT (%)

4. SPECIFIC GRAVITY

5. GHV (BTU/GAL) 126,353 Natural Gas - 1037 Btu/ft^3

I. COST DATA

ELECTRICITY

WATER

STEAM

J. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE?

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE?

K. OIL/GAS TO COAL CONVERSION DATA

1. HAS THE BOILER EVER BURNED COAL? Not Full Time-only for E[illegible] r[illegible]

Boiler No.	1	2			
Yes or No.	Yes	Yes			

2. SYSTEM AVAILABILITY

2.1 COAL HANDLING

a. Is the system still installed? Yes ☐ No ☐

b. Will it operate? ☐ ☐

c. Of the following items which need to be replaced:

	Yes	No
Unloading equipment	☐	☐
Stack Reclaimer	☐	☐
Bunkers	☐	☐
Conveyors	☐	☐
Scales	☐	☐
Coal Storage Area	☐	☐

2.2 FUEL FIRING

a. Is the system still installed? Yes ☐ No ☐

b. Will it operate? ☐ ☐

c. Of the following items which need to be replaced:

	Yes	No
Pulverizers or Crushers	☐	☐
Feed Ducts	☐	☐
Fans	☐	☐
Controls	☐	☐

2.3 GAS CLEANING - No equipment is currently installed

a. Is the system still installed? Yes ☐ No ☐

b. Will it operate? ☐ ☐

c. Of the following items which need to be replaced:

	Yes	No
Electrostatic Precipitator	☐	☐
Cyclones	☐	☐
Fly Ash Handling Equipment	☐	☐
Soot Blowers - Air Compressors	☐	☐
Wall deslaggers	☐	☐

2.4 ASH HANDLING

a.	Is the system still installed?	Yes ☒	No ☐
b.	Will it operate?	☐	☒
c.	Of the following items which need to be replaced:		
	Bottom Ash Handling	Yes ☒	No ☐
	Ash Pond	☒	☐

L. SUPPLEMENTARY CONTROL SYSTEM DATA

1. DOES THE PLANT NOW HAVE A SUPPLEMENTAL CONTROL SYSTEM (SCS)? Yes [ ] No [X]

   If yes, attach a description of the system.

2. IS THE PLANT CAPABLE OF SWITCHING TO LOW SULFUR FUELS? Yes [ ] No [ ]

   2.1 Storage capacity for low sulfur fuels (tons, bbls, days)

   2.2 Bunkers available for low sulfur coal storage? Yes [ ] No [ ]

   2.3 Handling facilities available for low sulfur fuels Yes [ ] No [ ]

   If yes, describe ______________________

   ____

   2.4 Time required to switch fuels and fire the low sulfur fuel in the boiler (hrs)?______

3. IS THE PLANT CAPABLE OF LOAD SHEDDING?

   If yes, discuss ______________________

   ______________________________________ Yes [ ] No [X]

4. IS THE PLANT CAPABLE OF LOAD SHIFTING?

   If yes, discuss ______________________

   ______________________________________ Yes [X] No [ ]

5. POWER PLANT MONITORING SYSTEM

   5.1 Existing system Yes [ ] No [ ]

   a. Air quality instrumentation

	Number	Type
(1) Sulfur Oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulates		
- Intermittent	______	______
- Static	______	______

   (3) Other (describe)____________

   b. Meteorological instrumentation

   If yes, describe ______________

   ____

   c. Is the monitoring data available? Yes [ ] No [ ]

   d. Is the monitoring data reduced and analyzed? Yes [ ] No [ ]

5.2 Proposed system Yes [ ] No [ ]

If yes, describe ____________________

____

a. Air monitoring instrumentation

	Number	Type
(1) Sulfur oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulate		
- Intermittent	______	______
- Static	______	______
(3) Other (describe) ____________		

b. Meteorological instrumentation

If yes, describe ____________________

____

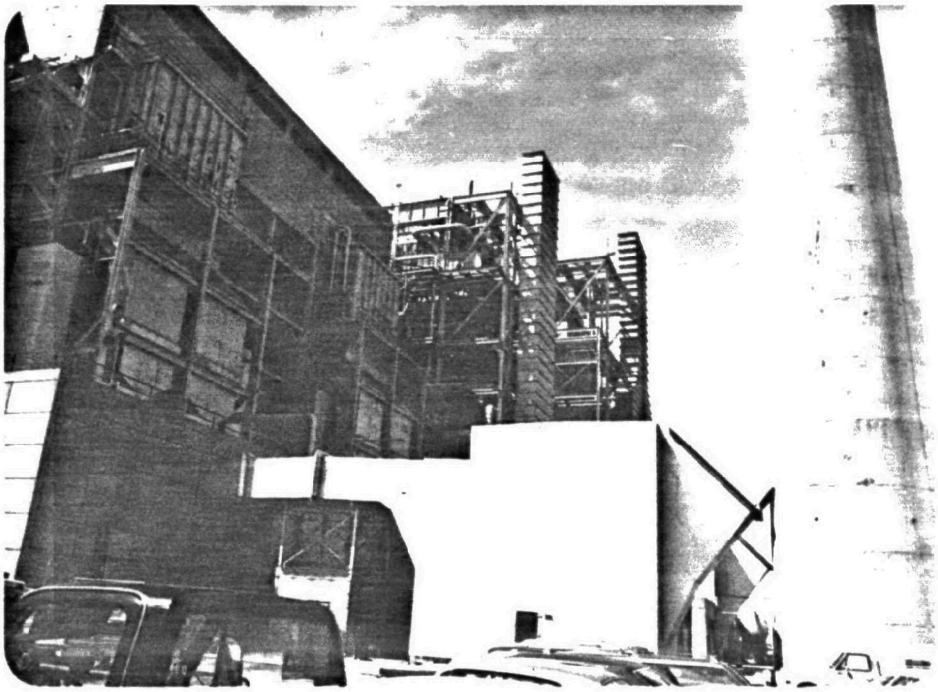


Photo No. 1 View from ground level facing west showing the induced fan house, duct work, and stack serving Boiler 1.

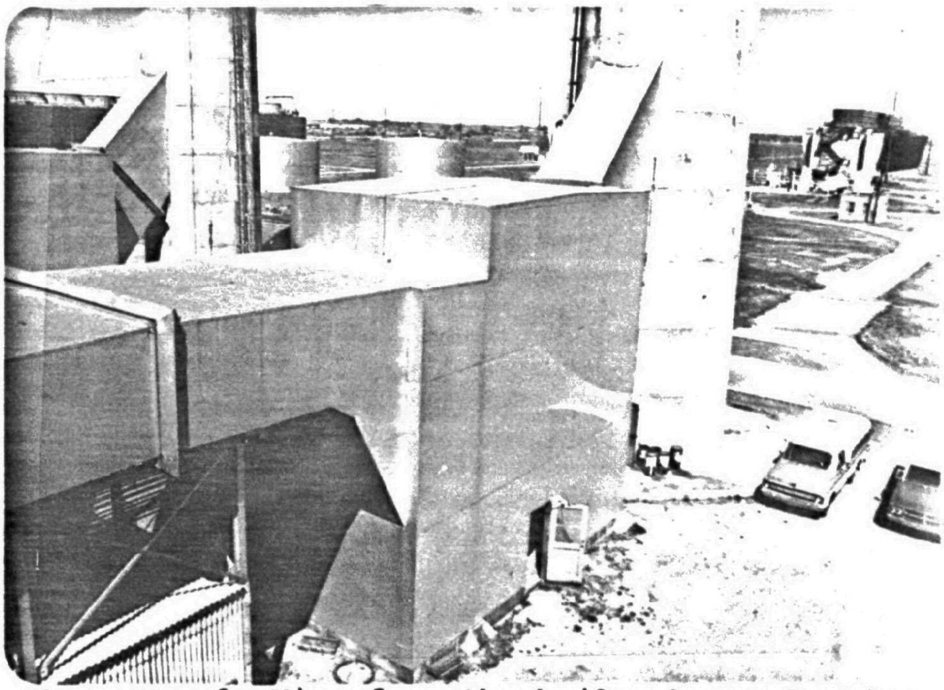


Photo No. 2 View from the boiler house looking northwest. Stacks 1 and 2 and their lead-in ducts are shown in the foreground of the photo. Cooling towers and oil storage tanks are shown in the background.

Photo No. 3 View from the boiler house facing northeast. Cooling towers and the waste water pit are shown.

Photo No. 4 View from boiler house roof looking west showing the coal pile and a portion of the coal conveying system.

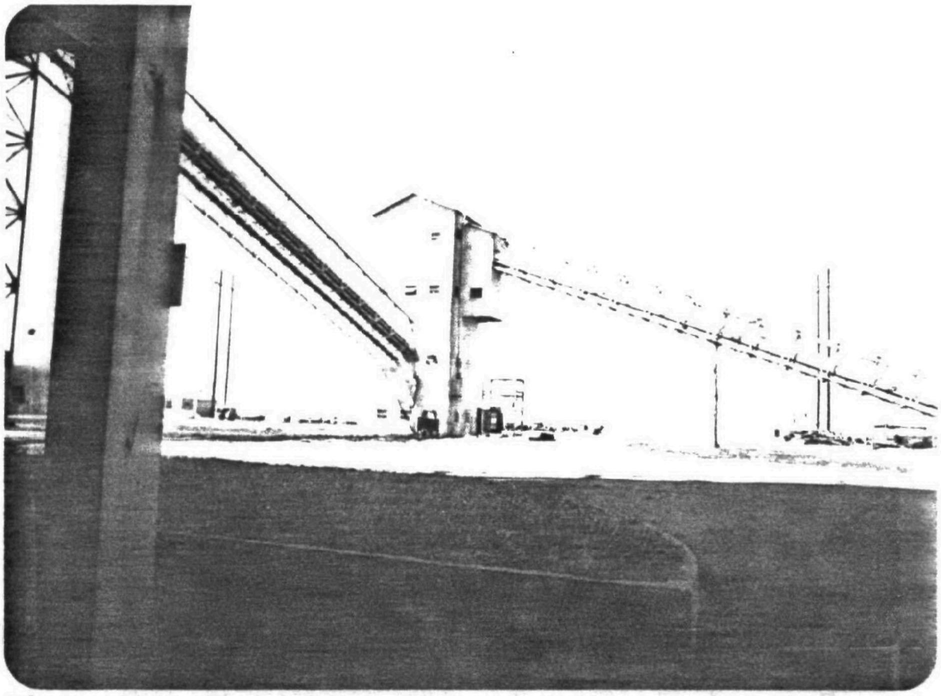


Photo No. 5 View from ground level facing south-west showing the coal conveyors and the transport house.

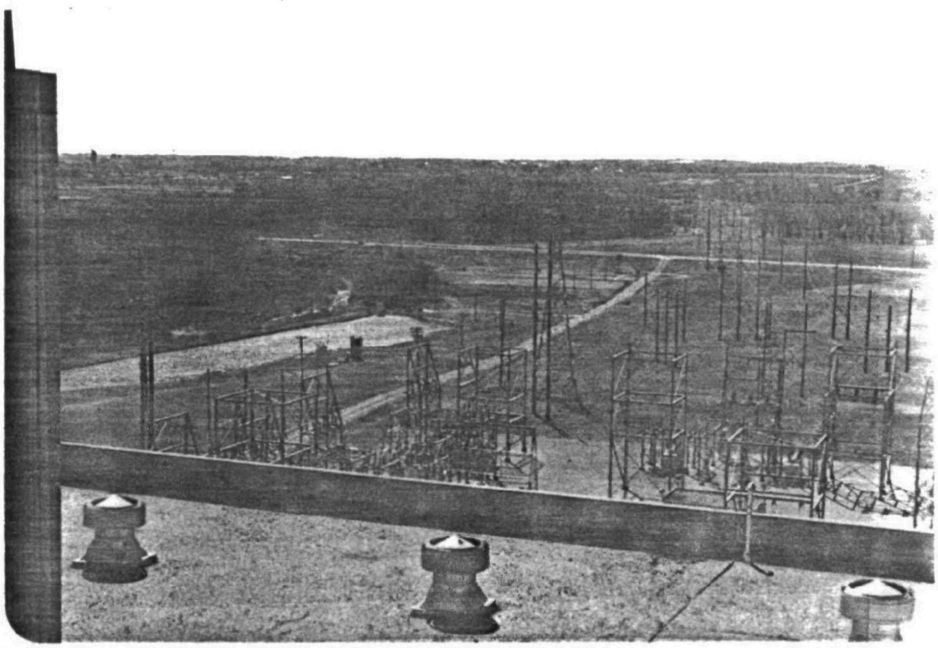


Photo No. 6 View from the boiler house roof looking southeast. A portion of a switchyard is shown in the foreground of the photo. The ash pond is shown in the left-center and the surrounding terrain is shown in the background of the photograph.

Photo No. 7 View from the boiler house roof facing north showing oil storage tanks, natural gas meter and regulator stations, and cooling towers.

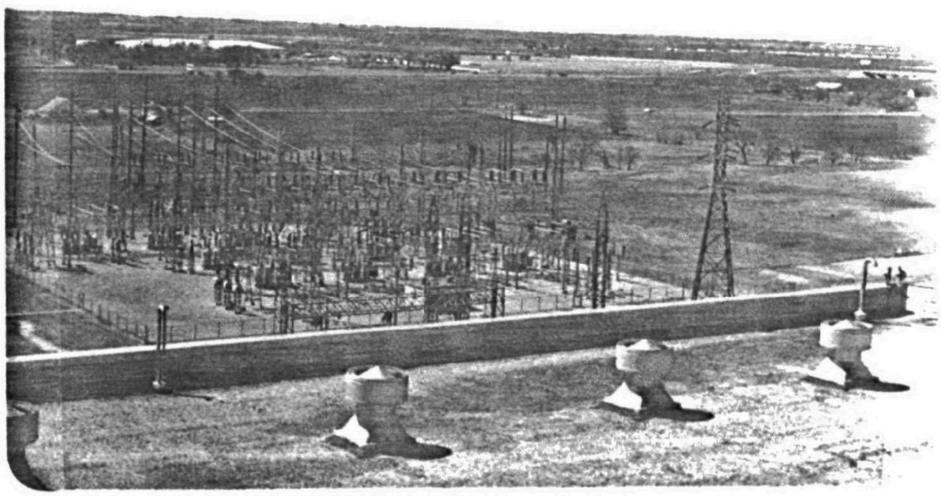


Photo No. 8 View from the boiler house roof looking south. The 138 KV substation is shown in the center of the photograph. The surrounding farmland is shown in the background.

Photo No. 9 View from the boiler house roof facing southwest. The top of the transfer house is shown in the lower left of the photo. The surrounding terrain and railroad lines are also shown.

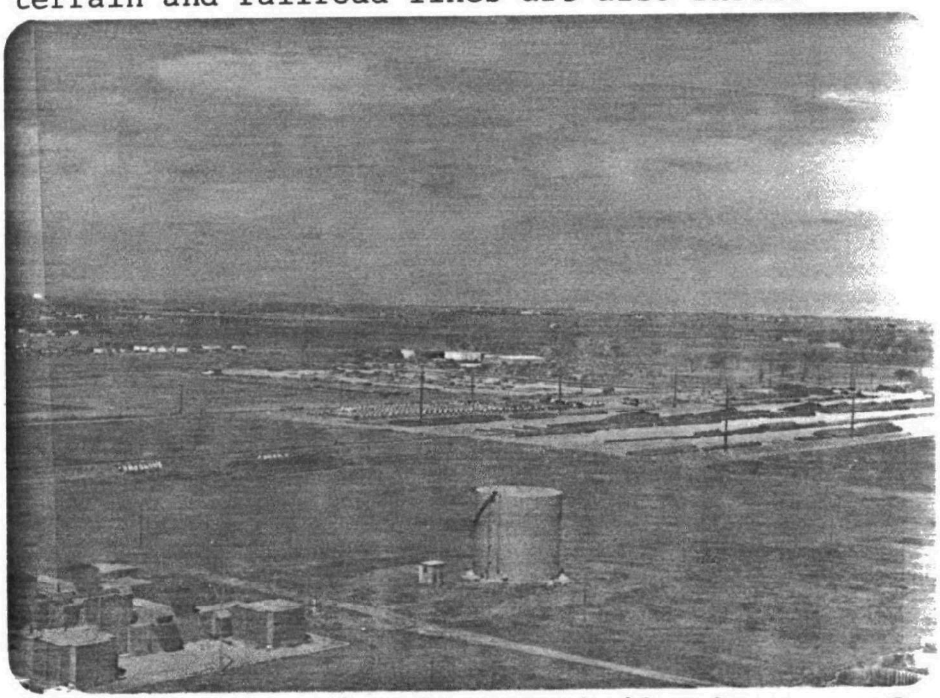


Photo No. 10 View from the boiler house roof looking northwest. Gas turbines are shown in the lower right and an oil storage tank is shown in the center of the photograph. A plant storage area is shown in the background.

TABLE M-1. ESTIMATED CAPITAL COST OF ELECTROSTATIC PRECIPITATORS FOR BOILERS 1 AND 2 AT THE MUSTANG POWER PLANT ON HIGH-SULFUR COAL (1978)

Direct Costs		
ESP		$ 1,617,000
Ash handling		134,000
Ducting		421,000
	Total direct costs	$ 2,172,000
Indirect Costs		
Interest during construction	8% of direct costs	$ 174,000
Contractor's fee	10% of direct costs	217,000
Engineering	6% of direct costs	130,000
Freight	1.25% of direct costs	27,000
Offsite	3% of direct costs	65,000
Taxes	0% of direct costs	000
Spares	1% of direct costs	22,000
Allowance for shakedown	3% of direct costs	65,000
Total indirect costs		$ 700,000
Contingency		574,000
Total		$ 3,446,000
Coal conversion costs		10,703,000
Grand total		$ 14,149,000
$/kW		119.91

TABLE M-2. ESTIMATED ANNUAL OPERATING COSTS OF ELECTROSATIC PRECIPITATOR FOR BOILERS 1 AND 2 AT THE MUSTANG POWER PLANT ON HIGH-SULFUR COAL (1978)

		Annual Costs
<u>Utilities</u>		
Electricity	335 kW at 27.5 mills/kWh	$ 33,000
Water	4794 x 10^3 gal/yr at $0.01/$10^3$ gal	1,000
<u>Operating Labor</u>		
Direct labor	0.5 man/shift at $7.52/h	66,000
Supervision	15% of direct labor	10,000
<u>Maintenance</u>		
Labor and materials	2% of fixed investment	69,000
Supplies	15% of labor and materials	10,000
<u>Overhead</u>		
Plant	50% of operating and maintenance	78,000
Payroll	20% of operating labor	15,000
<u>Additional Operating and Maintenance</u>		
Coal conversion		866,000
<u>Fixed costs</u>		
Depreciation	(8.33%)	
Interim replacement	(0.35%), Σ = 20.18% of fixed investment	
Insurance	(0.30%)	
Taxes	(0.00%)	
Capital cost	(11.20%)	
Total fixed cost		$ 695,000
Total cost		$ 1,843,000
Fuel credit		(2,145,000)
Net annual credit		$ (302,000)
Mills/kWh		0.71

Table M-3 . ELECTROSTATIC PRECIPITATOR DESIGN VALUES
FOR BOILER 1 AT THE MUSTANG POWER PLANT
ON HIGH- SULFUR COAL BURNING

Design Parameter	Value
Collection efficiency, % (Overall)	97.65
Specific collecting area, ft^2/1000 acfm	197
Total collecting area, ft^2	26,400
Superficial velocity, fps	4
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	15 x 37 x 19

Table M-4 . ELECTROSTATIC PRECIPITATOR DESIGN VALUES

FOR BOILER 2 AT THE MUSTANG POWER PLANT

ON HIGH-SULFUR COAL BURNING

Design Parameter	Value
Collection efficiency, % (Overall)	97.65
Specific collecting area, ft^2/1000 acfm	197
Total collecting area, ft^2	26,400
Superficial velocity, fps	4
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	15 x 37 x 19

TABLE M-5. ESTIMATED CAPITAL COST OF ELECTROSTATIC PRECIPITATORS FOR BOILERS 1 AND 2 AT THE MUSTANG POWER PLANT ON LOW-SULFUR COAL (1978)

<u>Direct Costs</u>		
ESP		$ 1,951,000
Ash handling		283,000
Ducting		388,000
	Total direct costs	$ 2,622,000
<u>Indirect Costs</u>		
Interest during construction	8% of direct costs	$ 210,000
Contractor's fee	10% of direct costs	262,000
Engineering	6% of direct costs	157,000
Freight	1.25% of direct costs	33,000
Offsite	3% of direct costs	79,000
Taxes	0% of direct costs	000
Spares	1% of direct costs	26,000
Allowance for shakedown	3% of direct costs	79,000
Total indirect costs		$ 846,000
Contingency		694,000
Total		$ 4,162,000
Coal conversion costs		10,703,000
Grand total		$ 14,865,000
$/kW		125.97

TABLE M-6. ESTIMATED ANNUAL OPERATING COSTS OF ELECTROSTATIC PRECIPITATORS FOR BOILERS 1 AND 2 AT THE MUSTANG POWER PLANT ON LOW-SULFUR COAL (1978)

		Annual Costs
Utilities		
Electricity	158 kW at 27.5 mills/kWh	$ 15,000
Water	4794 10^3 gal/yr at $0.01/$10^3$ gal	1,000
Operating Labor		
Direct labor	0.5 man/shift $7.52/h	66,000
Supervision	15% of direct labor	10,000
Maintenance		
Labor and materials	2% of fixed investment	83,000
Supplies	15% of labor and materials	13,000
Overhead		
Plant	50% of operating and maintenance	86,000
Payroll	20% of operating labor	15,000
Additional Operating and Maintenance		
Coal conversion		866,000
Fixed costs		
Depreciation	(8.33%)	
Interim replacement	(0.35%), Σ = 20.18% of fixed investment	
Insurance	(0.30%)	
Taxes	(0.00%)	
Capital cost	(11.20%)	
Total fixed cost		$ 840,000
Total cost		$ 1,995,000
Fuel cost		4,725,000
Net annual cost		$ 6,720,000
Mills/kWh		15.72

Table M-7 . ELECTROSTATIC PRECIPITATOR DESIGN VALUES
FOR BOILER 1 AT THE MUSTANG POWER PLANT
ON LOW-SULFUR COAL BURNING

Design Parameter	Value
Collection efficiency, % (Overall)	97.65
Specific collecting area, ft^2/1000 acfm	417
Total collecting area, ft^2	55,900
Superficial velocity, fps	4
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	30 x 19 x 42

Table M-8 . ELECTROSTATIC PRECIPITATOR DESIGN VALUES FOR BOILER 2 AT THE MUSTANG POWER PLANT ON LOW-SULFUR COAL BURNING

Design Parameter	Value
Collection efficiency, % (Overall)	97.65
Specific collecting area, ft^2/1000 acfm	417
Total collecting area, ft^2	55,900
Superficial velocity, fps	4
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	30 x 19 x 42

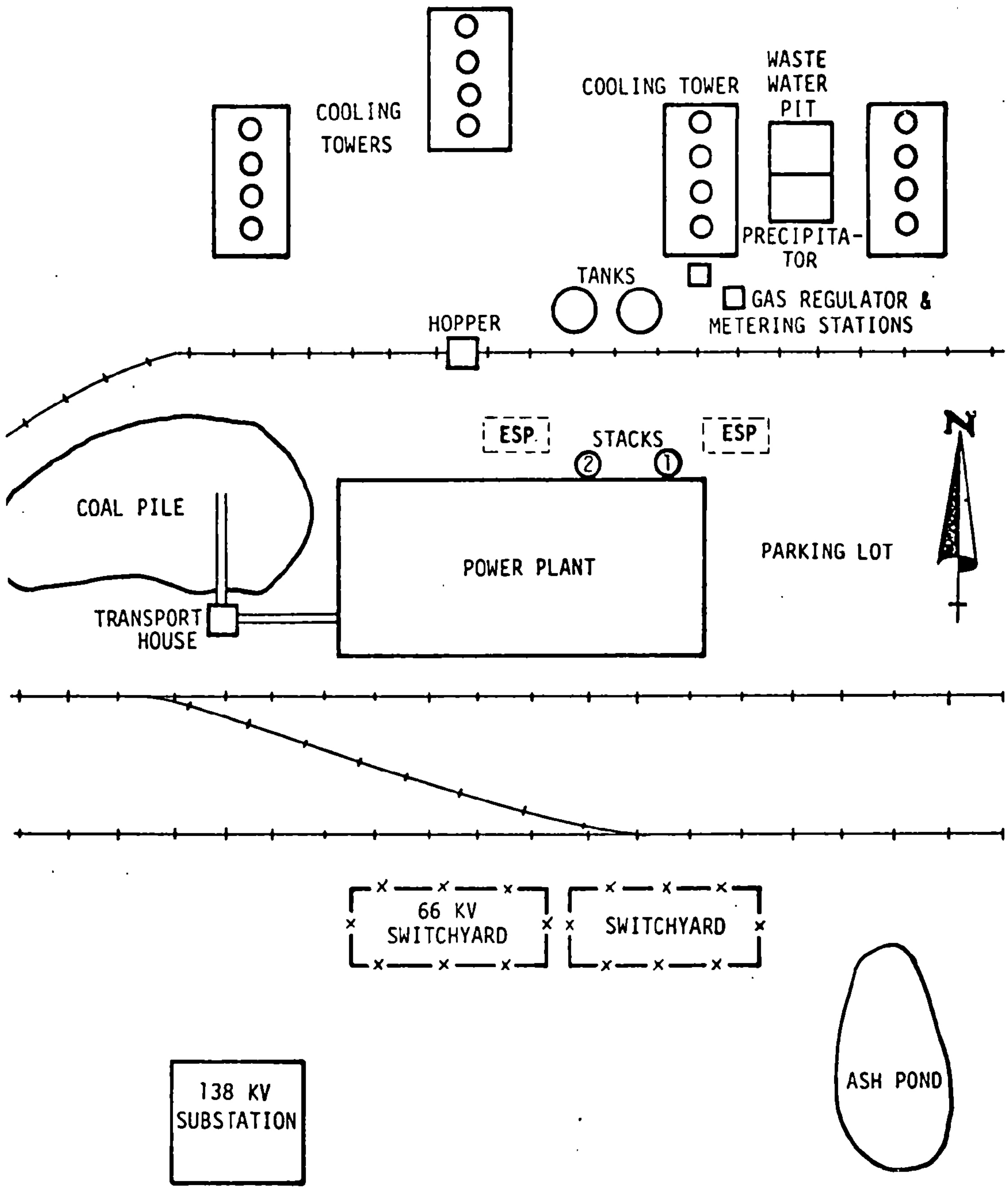


Figure M-1. Site plan showing possible locations of new ESP's for Boilers 1 and 2 at the Mustang power plant.

APPENDIX N

POSSUM POINT POWER PLANT

CONTENTS

FIGURES

TABLES

TABLES (continued)

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Virginia Electric & Power Co.
2. MAIN OFFICE: P.O. Box 26666, Richmond, Virginia 23261
3. RESPONSIBLE OFFICER: C. M. Stallings
4. POSITION: Vice President
5. PLANT NAME: Possum Point Power Station
6. PLANT LOCATION: Prince William County, Dumfries Va. 22026
7. RESPONSIBLE OFFICER AT PLANT LOCATION: Rolland Simmons
8. POSITION: Plant Superintendent
9. POWER POOL

DATE INFORMATION GATHERED: April 21, 1976

PARTICIPANTS IN MEETING:

Ned Kirby - VEPCO - Richmond
Ken Newsome - VEPCO - Richmond
Jim Cassada VEPCO - Richmond
Joe O'Rear - VEPCO - Richmond
Bob Combs - VEPCO - Richmond
R. H. Hilliard - VEPCO-Possum Point
Rolland Simmons - VEPCO- Possum Point
Bernie Turlinski - U.S. Environmental Protection Agency
Daniel J. Gaston - Virginia Air Pollution Control Board
Frank Lalley - Federal Energy Administration
Thomas C. Ponder, Jr. - PEDCo Environmental, Inc.
N. David Noe - PEDCo Environmental, Inc.
David M. Augenstein - PEDCo Environmental, Inc.

	Boiler number				
B. ATMOSPHERIC EMISSIONS					
1. PARTICULATE EMISSIONS[a]					
LB/MM BTU					
GRAINS/ACF					
LB/HR (FULL LOAD)					
TONS/YEAR ( )					
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION					
REGULATION & SECTION NO.	Part IV Rule Ex - 3 4.30 (a) 11				
LB/MM BTU	0.1 lb/mm Btu				
	less than 20% opacity (Rule Ex - 2)				
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a]					
LB/MM BTU					
LB/HR (FULL LOAD)					
TONS/YEAR ( )					
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.	Part IV Rule Ex - 5, 4.51 (a) 1				
LB/MM BTU	1.06 lb/mm Btu SO_2				
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					

a) Identify whether results are from stack tests or estimates

C. SITE DATA

1. U.T.M. COORDINATES ____________________

2. ELEVATION ABOVE MEAN SEA LEVEL (FT) ____________________

3. SOIL DATA: BEARING VALUE ____________________

   PILING NECESSARY ____________________

4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA

5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE)

6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): ____________________

D. BOILER DATA

	Boiler number 1	2	3	4	5
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK	Float	Float	Float	Float	Floating
2. TOTAL HOURS OPERATION (1975)	6,572.50	7,243.75	5,057.60	7,043.36	3,585.38
3. AVERAGE CAPACITY FACTOR (1975)	39.0	48.0	34.0	57.0	23.3
4. SERVED BY STACK NO.	1	2	3	4	5
5. BOILER MANUFACTURER	CE	CE	CE	CE	CE
6. YEAR BOILER PLACED IN SERVICE	1948	1951	1955	1962	1975
7. REMAINING LIFE OF UNIT					
8. GENERATING CAPACITY (MW)					
RATED	69	69	113.64	239.36	882
MAXIMUM CONTINUOUS - Summer	74	69.2	101	232.9	805
PEAK					
9. FUEL CONSUMPTION:					
COAL (TPH) OR (GPH) MAXIMUM CONTINUOUS — TPH coal	31.5	29.6	38.5	78.3	0
BBL/Hr. oil	132	140	162	338	1,220
10. ACTUAL FUEL CONSUMPTION					
COAL (TPY) (1975)	-	-	-	-	-
OIL (1975) BBL/yr	525,050	577,950	551,950	1,970,600	3,212,690
11. WET OR DRY BOTTOM	Dry	Dry	Dry	Dry	NA
12. FLY ASH REINJECTION (YES OR NO)	Yes	Yes	Yes	Yes	Yes
13. STACK HGT ABOVE GRADE (FT.)	175	175	177	175	358.5
14. I.D. OF STACK AT TOP (INCHES)	156	156	156	168	276

Notes:

	Boiler number				
	1	2	3	4	5
15. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS					
MANUFACTURER	N/A	N/A	N/A	N/A	UOP
TYPE					MCAX
EFFICIENCY: DESIGN/ACTUAL (%)					91.2
MASS EMISSION RATE:					
(GR/ACF)					
(#/HR)					206
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER	COTT	COTT	COTT	COTT	N/A
TYPE	E	E	E	E	
EFFICIENCY: DESIGN/ (%)	95	96	96	96	
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)	249.7	170	210.7	428.5	
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)					
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)					
16. EXCESS AIR: DESIGN/ACTUAL (%)					

Notes:

	Boiler number 1	2	3	4	5
17. FLUE GAS RATE (ACFM)					
@ 100% LOAD	322,321	273,726	338,099	650,385	2,080,100
@ 75% LOAD	247,217	210,945	259,259	492,435	1,583,500
@ 50% LOAD	172,556	144,692	186,502	334,125	1,103,500
18. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	364	303	277	265	260
@ 75% LOAD	330	275	265	246	255
@ 50% LOAD	311	255	246	219	249
19. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	40.5	34.4	42.5	70.4	83.4
@ 75% LOAD	31.0	26.5	32.6	53.3	63.5
@ 50% LOAD	21.7	18.2	23.4	36.2	44.3
20. FLY ASH: TOTAL COLLECTED (TONS/YEAR)	0.6 cal				
DISPOSAL METHOD	Land fill				
DISPOSAL COST ($/Yr.)	30,700				
21. BOTTOM ASH: TOTAL COLLECTED (~~TONS~~/ YEAR)	0.1 cal				
DISPOSAL METHOD	Land fill				
DISPOSAL COST ($/~~TON~~)	7,000				
22. EXHAUST DUCT DIMENSIONS @ STACK					
23. ELEVATION OF TIE IN POINT TO STACK					
24. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)					

a) Identify source of values (test or estimate)

Notes:

	Boiler number				
E. I.D. FAN DATA					
1. MAXIMUM STATIC HEAD (IN. W.C.)					
2. WORKING STATIC HEAD (IN. W.C.)					

Notes:

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES)
2. YEARS STORAGE (ASH ONLY)
3. DISTANCE FROM STACK (FT.)
4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION
   a.
   b.
   c.
   d.
2. QUANTITY USED BY SEAM AND/OR MINE
   a.
   b.
   c.
   d.
3. ANALYSIS
   GHV (BTU/LB)
   S (%)
   ASH (%)
   MOISTURE (%)
4. PPT PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA

1. TYPE #2
2. S CONTENT (%) 1.4
3. ASH CONTENT (%)
4. SPECIFIC GRAVITY
5. GHV (BTU/GAL) 146,680

I. COST DATA

ELECTRICITY

WATER

STEAM

J. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE?

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE?

K. OIL/GAS TO COAL CONVERSION DATA

1. HAS THE BOILER EVER BURNED COAL?

Boiler No.	1	2	3	4	5
Yes or No.	Yes	Yes	Yes	Yes	No

2. SYSTEM AVAILABILITY

2.1 COAL HANDLING

a. Is the system still installed? Yes ☒ No ☐ Running OK

b. Will it operate? ☐ ☐

c. Of the following items which need to be replaced:

	Yes	No
Unloading equipment Repair	☒	☐
Stack Reclaimer	☒	☐
Bunkers	☒	☐
Conveyors	☒	☐
Scales	☐	☒
Coal Storage Area	☒	☐

2.2 FUEL FIRING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☐ ☒

c. Of the following items which need to be replaced:

	Yes		No
Pulverizers or Crushers	☒		☐
Some replaced by fly ash reinject ---- Feed Ducts	☐	x	☐
Fans	☒		☐
Controls	☒		☐

2.3 GAS CLEANING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☒ ☐

c. Of the following items which need to be replaced:

	Yes		No
Electrostatic Precipitator	☒		☐
Cyclones	☒ on 4		☐
Fly Ash Handling Equipment	☒		☐
Soot Blowers - Air Compressors	☐	x	☐
Wall deslaggers	☒		☐

2.4 ASH HANDLING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☒ ☐

c. Of the following items which need to be replaced:

	Yes		No
Bottom Ash Handling	☒		☐
Ash Pond	☐	x	☐

L. SUPPLEMENTARY CONTROL SYSTEM DATA

1. DOES THE PLANT NOW HAVE A SUPPLEMENTAL CONTROL SYSTEM (SCS)? Yes ☐ No ☐

   If yes, attach a description of the system.

2. IS THE PLANT CAPABLE OF SWITCHING TO LOW SULFUR FUELS? Yes ☐ No ☐

   2.1 Storage capacity for low sulfur fuels (tons, bbls, days)

   2.2 Bunkers available for low sulfur coal storage? Yes ☐ No ☐

   2.3 Handling facilities available for low sulfur fuels Yes ☐ No ☐

   If yes, describe ____________________

   ____

   2.4 Time required to switch fuels and fire the low sulfur fuel in the boiler (hrs)?______

3. IS THE PLANT CAPABLE OF LOAD SHEDDING?

   If yes, discuss ____________________

   ________________________________ Yes ☐ No ☐

4. IS THE PLANT CAPABLE OF LOAD SHIFTING?

   If yes, discuss ____________________

   ________________________________ Yes ☐ No ☐

5. POWER PLANT MONITORING SYSTEM

   5.1 Existing system Yes ☐ No ☐

   a. Air quality instrumentation

		Number	Type
(1) Sulfur Oxides	- Continuous	______	______
	- Intermittent	______	______
	- Static	______	______
(2) Suspended particulates	- Intermittent	______	______
	- Static	______	______
(3) Other (describe)____________			

   b. Meteorological instrumentation

   If yes, describe ____________________

   ____

   c. Is the monitoring data available? Yes ☐ No ☐

   d. Is the monitoring data reduced and analyzed? Yes ☐ No ☐

5.2 Proposed system — Yes ☐ No ☐

If yes, describe ______________________

____

a. Air monitoring instrumentation

	Number	Type
(1) Sulfur oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulate		
- Intermittent	______	______
- Static	______	______
(3) Other (describe) __________		

b. Meteorological instrumentation

If yes, describe ______________

____

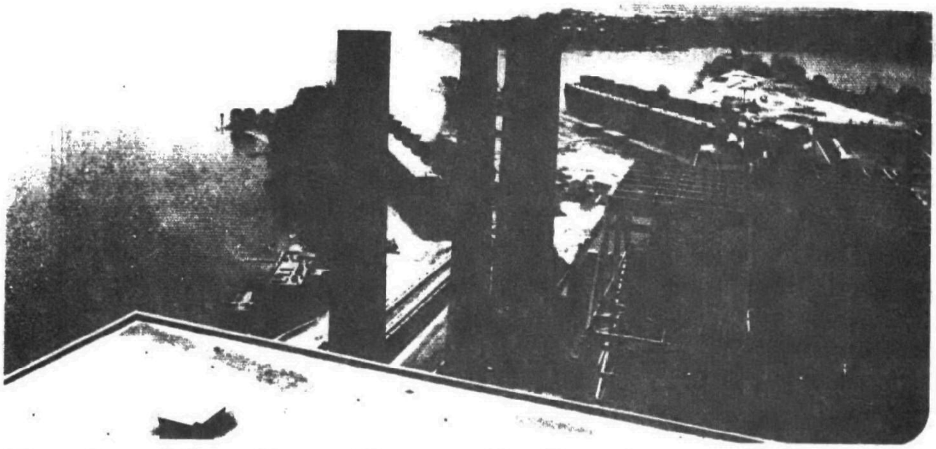


Photo No. 1. View from the roof of Boiler 5 facing south showing stacks 1, 2, 3, and 4. Cooling towers and Potomac River are in the background.

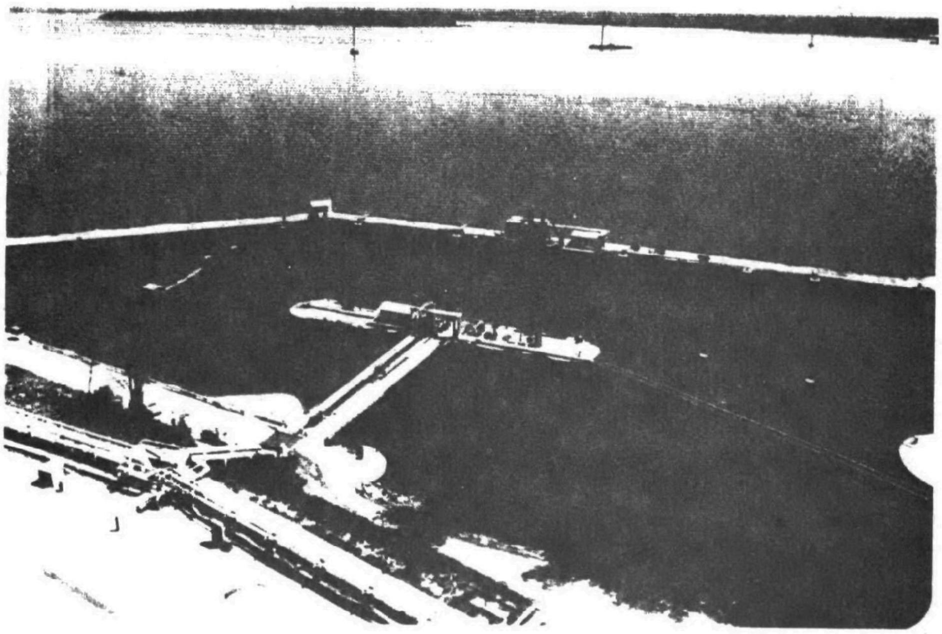


Photo No. 2. View from the roof of Boiler 5 facing north-east showing oil tanker unloading facilities on the Potomac.

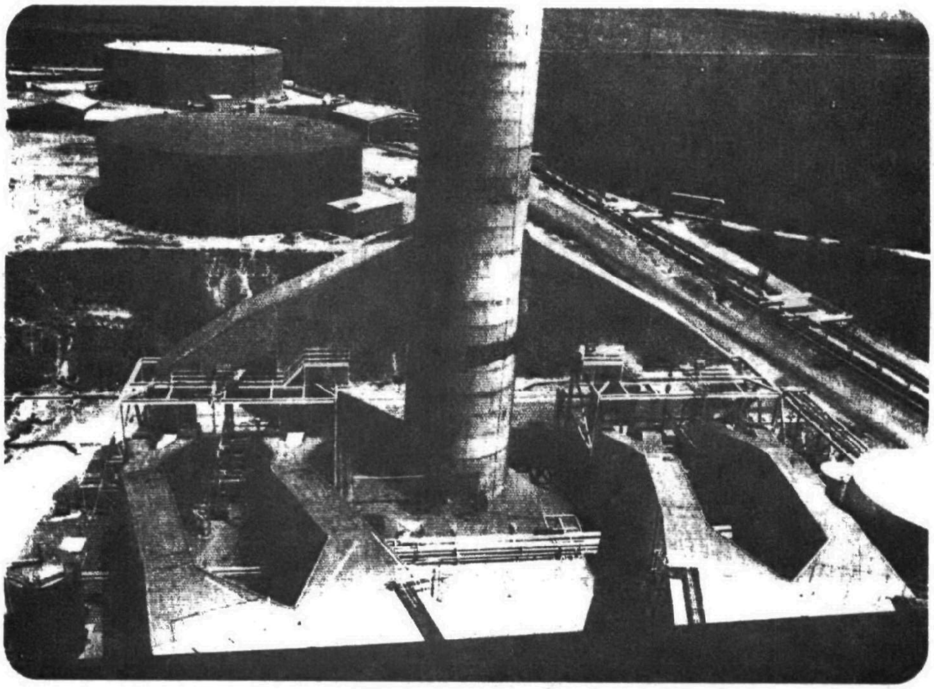


Photo No. 3. View from the roof of Boiler 5 facing north showing Boiler 5 duct tie-ins to the stack. Oil storage tanks are shown in the background.

Photo No. 4. View from the roof of Boiler 5 facing northwest showing oil storage facilities and electrical substation.

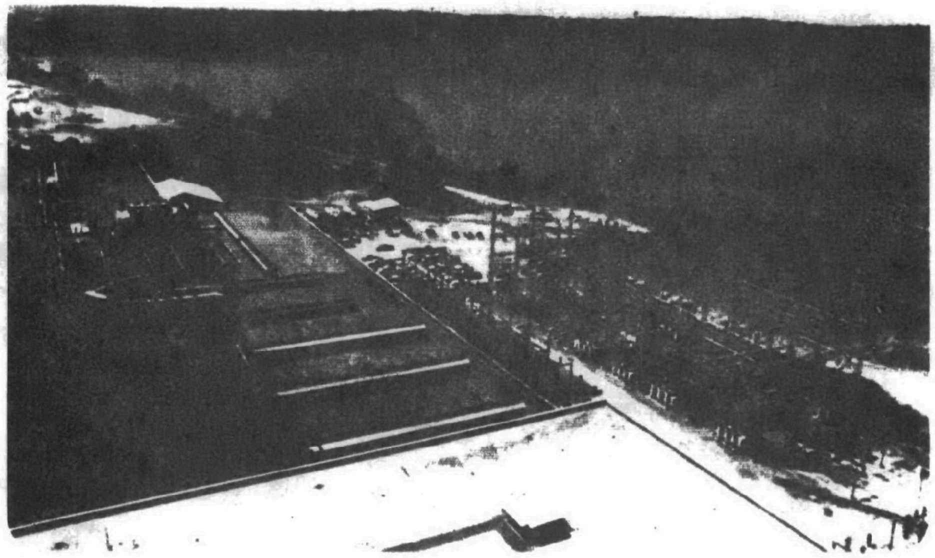


Photo No. 5. View from the roof of Boiler 5 facing southwest showing an electrical substation, coal storage area and the Potomac River.

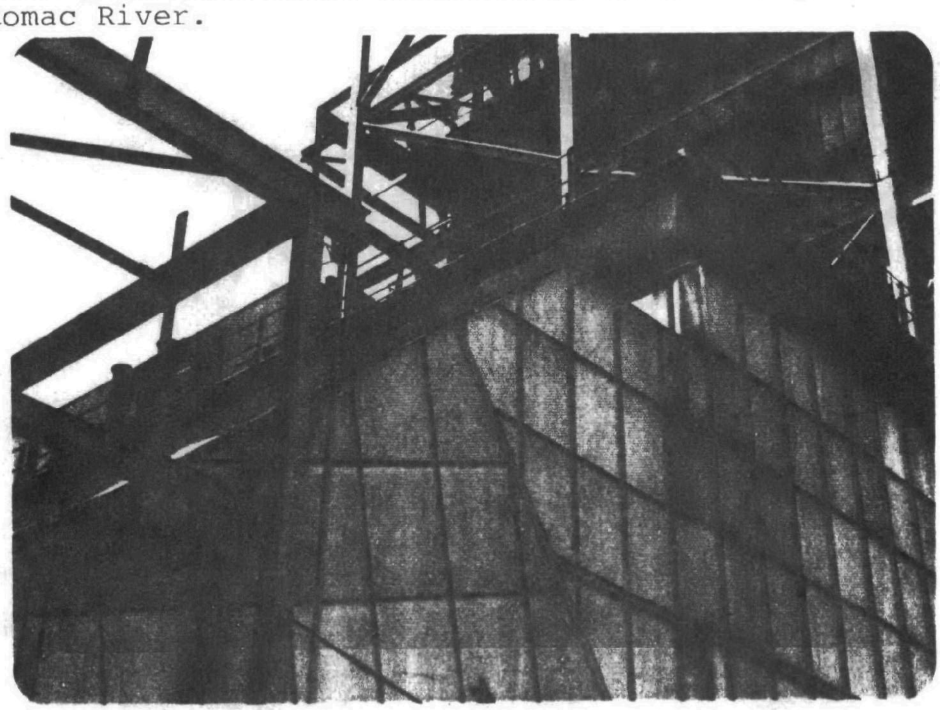


Photo No. 6. View from ground level showing electrostatic precipitator serving Boiler 4 located on the northeast end of the plant.

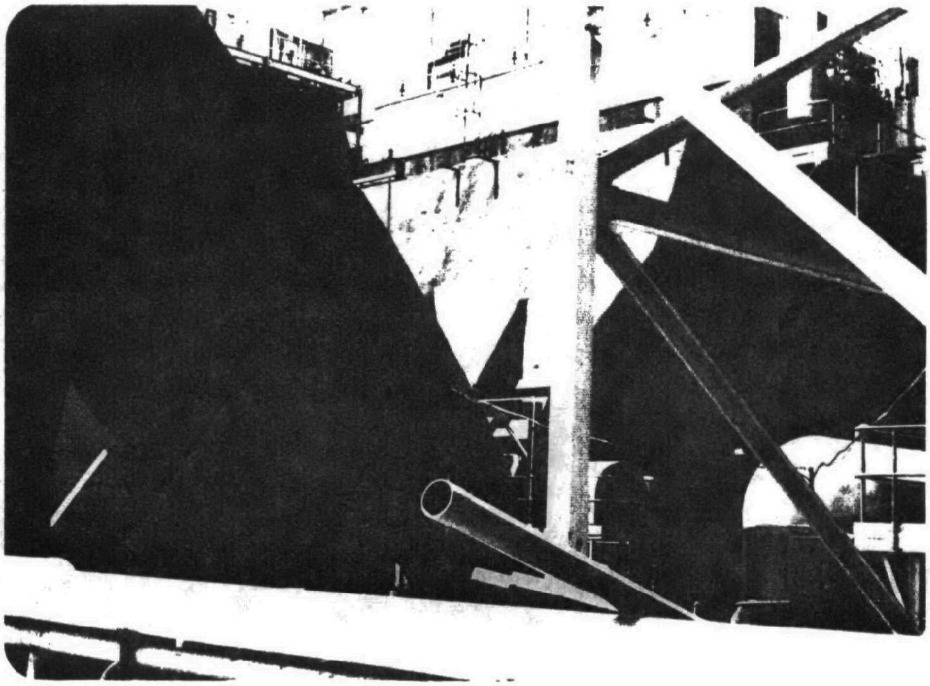


Photo No. 7. View from ground level showing electrostatic precipitator and tie-in to stack serving Boiler 3 located on the east end of the plant.

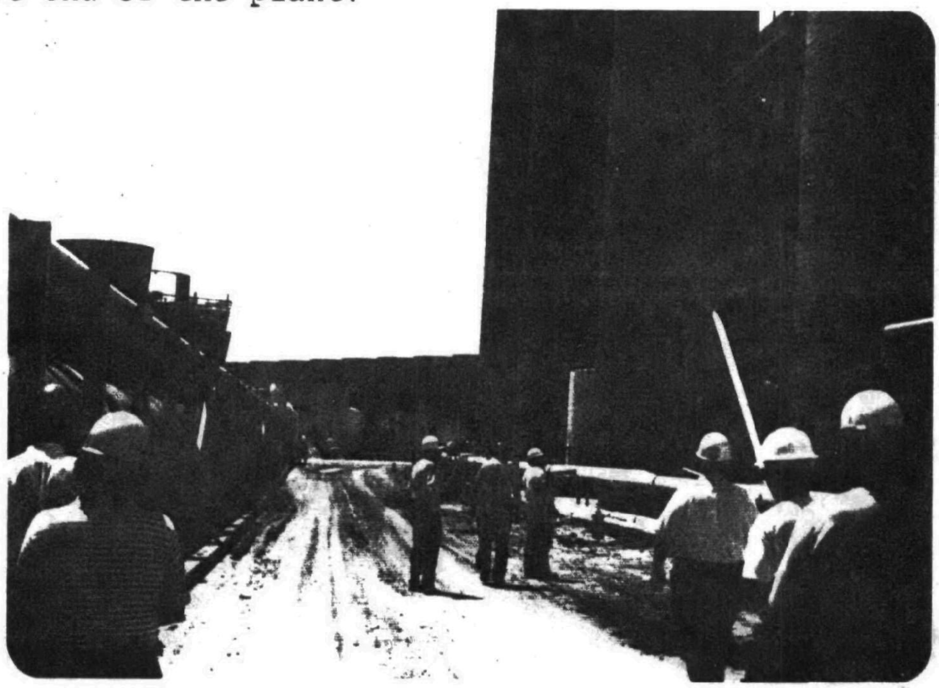


Photo No. 8. View from ground level facing south showing available space behind Stacks 1, 2, 3, and 4 on the east end of the plant.

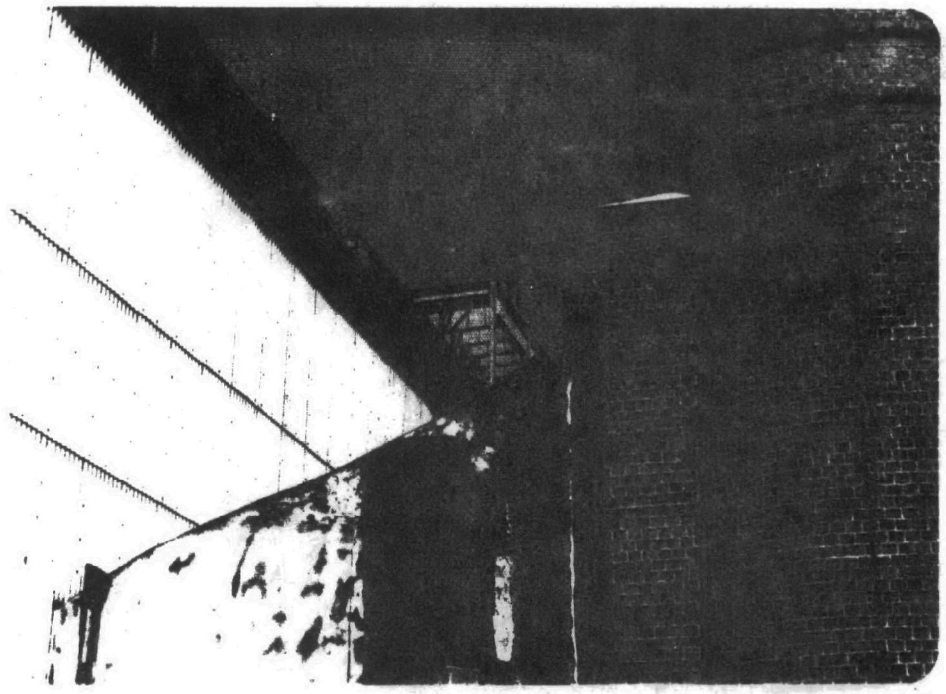


Photo No. 9. View from ground level facing north showing electrostatic precipitator and tie-in duct serving Boiler 1.

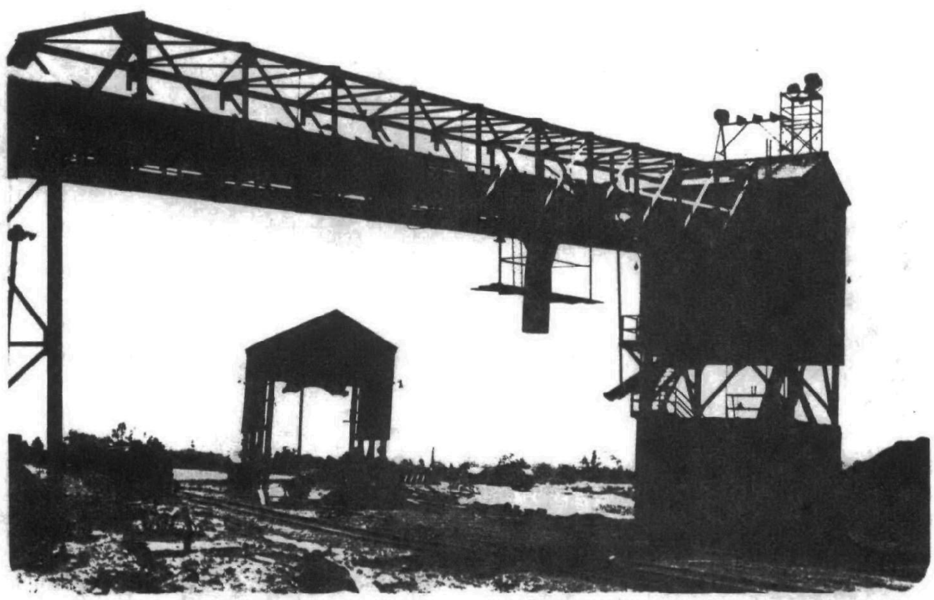


Photo No. 10. View from ground level facing south showing coal handling facilities. A portion of the coal storage area is also shown.

TABLE N-1. ESTIMATED CAPITAL COST FOR AN ELECTROSTATIC PRECIPITATOR FOR BOILER 2 AT THE POSSUM POINT POWER PLANT (1978)

<u>Direct Costs</u>		
ESP		$2,356,000
Ash handling		850,000
Ducting		356,000
Total direct costs		$3,562,000
<u>Indirect Costs</u>		
Interest during construction	10% of direct costs	$ 356,000
Contractor's fee	10% of direct costs	356,000
Engineering	10% of direct costs	356,000
Freight	1.25% of direct costs	45,000
Offsite	3% of direct costs	107,000
Taxes	0% of direct costs	000
Spares	1% of direct costs	36,000
Allowance for shakedown	3% of direct costs	107,000
Total indirect costs		$1,363,000
Contingency		985,000
Total		$5,910,000
Coal conversion costs		137,000
Grand total		$6,047,000
$/kW		87.38

TABLE N-2. ESTIMATED ANNUAL OPERATING COST OF AN ELECTROSTATIC PRECIPITATOR FOR BOILER 2 AT THE POSSUM POINT POWER PLANT (1978)

Utilities	Quantity	Unit Cost	Annual Cost
Electricity	466 kW	27.50 mills/kWh	$ 53,000
Water	1×10^3 gal/h	$\$0.01/10^3$ gal	1,000
Operating Labor			
Direct labor	0.5 man/shift	$8.50/man-hour	37,000
Supervision	15% of direct labor		6,000
Maintenance			
Labor and materials	2% of fixed investment		118,000
Supplies	15% of labor and materials		18,000
Overhead			
Plant	50% of operation and maintenace		90,000
Payroll	20% of operating labor		9,000
Trucking			
Bottom/fly ash removal			000
Fixed Costs			
Depreciation	(7.69%)		
Interim replacement	(0.35%), Σ = 19.54% of fixed investment		
Insurance	(0.30%)		
Taxes	(0.00%)		
Capital cost	(11.20%)		
Total fixed cost			$1,155,000
Total cost			$1,487,000
Fuel credit			(651,000)
Net annual cost			$ 836,000
Mills/kWh			2.87

TABLE N-3. ELECTROSTATIC PRECIPITATOR DESIGN VALUES FOR BOILER 2 AT THE POSSUM POINT POWER PLANT

Design Parameter	Values
Collection efficiency, % (Overall)	97.40
Specific collecting area, ft^2/1000 acfm	568
Total collecting area, ft^2	155,400
Superficial velocity, ft/s	4.0
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	42 x 29 x 50

TABLE N-4. ESTIMATED CAPITAL COST OF AN ELECTROSTATIC PRECIPITATOR FOR BOILER 3 AT THE POSSUM POINT POWER PLANT (1978)

Direct Costs		
ESP		$ 2,430,000
Ash handling		945,000
Ducting		387,000
Total direct costs		$ 3,762,000
Indirect Costs		
Interest during construction	10% of direct costs	$ 376,000
Contractor's fee	10% of direct costs	376,000
Engineering	10% of direct costs	376,000
Freight	1.25% of direct costs	47,000
Offsite	3% of direct costs	113,000
Taxes	0% of direct costs	000
Spares	1% of direct costs	38,000
Allowance for shakedown	3% of direct costs	113,000
Total indirect costs		$1,439,000
Contingency		1,040,000
Total		$6,241,000
Coal conversion costs		213,000
Grand total		$6,454,000
$/kW		63.90

TABLE N-5. ESTIMATED ANNUAL OPERATING COST OF AN ELECTROSTATIC PRECIPITATOR FOR BOILER 3 AT THE POSSUM POINT POWER PLANT (1978)

Utilities	Quantity	Unit Cost	Annual Cost
Electricity	538 kW	27.50 mills/kWh	$ 43,000
Water	1×10^3 gal/h	$\$0.01/10^3$ gal	1,000
Operating Labor			
Direct labor	0.5 man/shift	$8.50/man-hour	37,000
Supervision	15% of direct labor		6,000
Maintenance			
Labor and materials	2% of fixed investment		125,000
Supplies	15% of labor and materials		19,000
Overhead			
Plant	50% of operation and maintenace		94,000
Payroll	20% of operating labor		9,000
Trucking			
Bottom/fly ash removal			000
Fixed Costs			
Depreciation	(5.88%)		
Interim replacement	(0.35%), Σ = 17.73% of fixed investment		
Insurance	(0.30%)		
Taxes	(0.00%)		
Capital cost	(11.20%)		
Total fixed cost			$1,107,000
Total cost			$1,441,000
Fuel cost			387,000
Net annual cost			$1,828,000
Mills/kWh			6.08

TABLE N-6. ELECTROSTATIC PRECIPITATOR DESIGN VALUES FOR BOILER 3 AT THE POSSUM POINT POWER PLANT

Design Parameter	Values
Collection efficiency, % (Overall)	97.40
Specific collecting area, ft^2/1000 acfm	531
Total collecting area, ft^2	179,634
Superficial velocity, ft/s	4.0
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	39 x 38 x 47

TABLE N-7. ESTIMATED CAPITAL COST OF AN ELECTROSTATIC PRECIPITATOR FOR BOILER 4 AT THE POSSUM POINT POWER PLANT (1978)

Direct Costs		
ESP		$ 3,463,000
Ash handling		1,455,000
Ducting		523,000
Total direct costs		$ 5,441,000
Indirect Costs		
Interest during construction	10% of direct costs	$ 544,000
Contractor's fee	10% of direct costs	544,000
Engineering	10% of direct costs	544,000
Freight	1.25% of direct costs	68,000
Offsite	3% of direct costs	163,000
Taxes	0% of direct costs	000
Spares	1% of direct costs	54,000
Allowance for shakedown	3% of direct costs	163,000
Total indirect costs		$ 2,080,000
Contingency		1,504,000
Total		$ 9,025,000
Coal conversion costs		341,000
Grand total		$ 9,366,000
$/kW		40.21

TABLE N-8. ESTIMATED ANNUAL OPERATING COST OF AN ELECTROSTATIC PRECIPITATOR FOR BOILER 4 AT THE POSSUM POINT POWER PLANT (1978)

Utilities	Quantity	Unit Cost	Annual Cost
Electricity	863 kW	27.50 mills/kWh	$ 118,000
Water	3×10^3 gal/h	$\$0.01/10^3$ gal	1,000
Operating Labor			
Direct labor	0.5 man/shift	$8.50/man-hour	37,000
Supervision	15% of direct labor		6,000
Maintenance			
Labor and materials	2% of fixed investment		181,000
Supplies	15% of labor and materials		27,000
Overhead			
Plant	50% of operation and maintenace		126,000
Payroll	20% of operating labor		9,000
Trucking			
Bottom/fly ash removal			000
Fixed Costs			
Depreciation	(4.17%)		
Interim replacement	(0.35%), Σ = 16.02% of fixed investment		
Insurance	(0.30%)		
Taxes	(0.00%)		
Capital cost	(11.20%)		
Total fixed cost			$ 1,446,000
Total cost			$ 1,951,000
Fuel credit			(3,696,000)
Net annual credit			$(1,745,000)
Mills/kWh			1.50

TABLE N-9. ELECTROSTATIC PRECIPITATOR DESIGN VALUES FOR BOILER 4 AT THE POSSUM POINT POWER PLANT

Design Parameter	Values
Collection efficiency, % (Overall)	97.40
Specific collecting area, ft^2/1000 acfm	442
Total collecting area, ft^2	287,760
Superficial velocity, ft/s	4.0
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	33 x 83 x 40

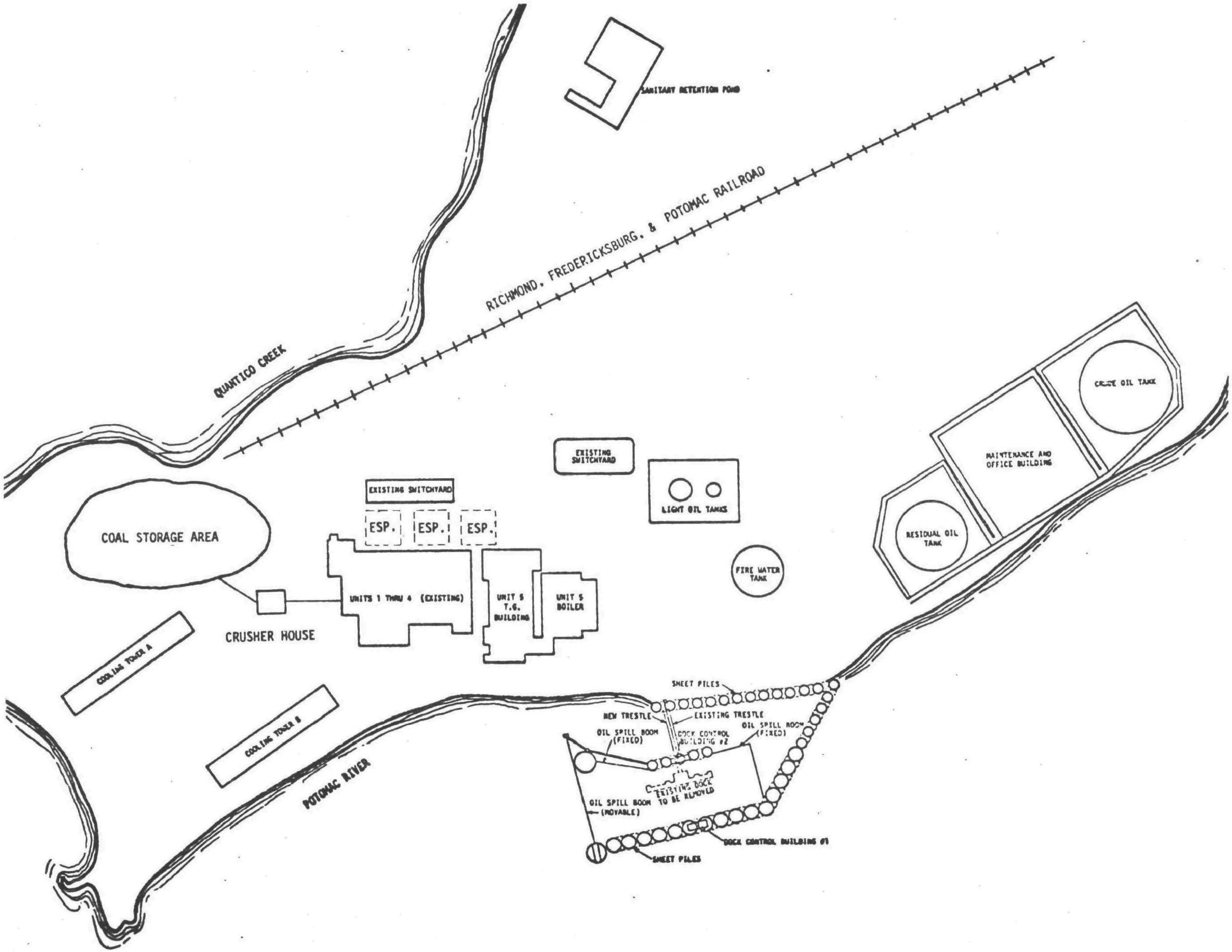


Figure N-1. Site plan showing possible locations of new ESP's for Boilers 2, 3, and 4 at the Possum Point power plant.

APPENDIX O

RAVENSWOOD POWER PLANT

CONTENTS

FIGURES

TABLES

TABLES (continued)

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Consolidated Edison Company
2. MAIN OFFICE: 4 Irving Place, New York, New York 10003
3. RESPONSIBLE OFFICER: John J. Grob, Jr.
4. POSITION: Chief Nuclear and Emission Control Engineer
5. PLANT NAME: Ravenswood
6. PLANT LOCATION: Queens, New York
7. RESPONSIBLE OFFICER AT PLANT LOCATION: Gene McGrath
8. POSITION: Plant Superintendent
9. POWER POOL N.Y. P.P.

DATE INFORMATION GATHERED: June 30, 1976

PARTICIPANTS IN MEETING:

Bertrum D. Moll	Consolidated Edison Company
Demarest Romaine	Consolidated Edison Company
Peter C. Freudenthal	Consolidated Edison Company
John J. Grob	Consolidated Edison Company
Ralph Morgan	Consolidated Edison Company
Ray Werner	USEPA - II - Air Branch
Robert N. Ogg	USEPA - II - Air Facilities Branch
Richard T. Price	PEDCo Environmental, Inc.
N. David Noe	PEDCo Environmental, Inc.
Thomas C. Ponder	PEDCo Environmental, Inc.

	Boiler number				
B. ATMOSPHERIC EMISSIONS	10	20	30		
1. PARTICULATE EMISSIONS[a] Oil					
LB/MM BTU			0.06		
GRAINS/ACF					
LB/HR (FULL LOAD)					
TONS/YEAR (1975)			1284		
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION	I	I	I		
REGULATION & SECTION NO.	--------Part 227.3 (c)--------				
LB/MM BTU	0.10	0.10	0.10		
OPACITY, PERCENT					
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a] Oil					
LB/MM BTU			0.29		
LB/HR (FULL LOAD)					
TONS/YEAR ( )			6805		
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.	-------Part 225 Table I------				
LB/MM BTU	0.33	0.33	0.33		
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					

a) Identify whether results are from stack tests or estimates

C. SITE DATA

1. U.T.M. COORDINATES ____________________

2. ELEVATION ABOVE MEAN SEA LEVEL (FT) ____________________

3. SOIL DATA: BEARING VALUE ____________________

   PILING NECESSARY ____________________

4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA

5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE)

6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): ____________________

D. BOILER DATA

	Boiler number				
	10	20	30 N	30 S	
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK					
2. TOTAL HOURS OPERATION (1975)	7862	6228	7552	7333	
3. AVERAGE CAPACITY FACTOR (1975)	67.8	55.7	63.6	62.5	
4. SERVED BY STACK NO.	1	2	3	3	
5. BOILER MANUFACTURER	CE	CE	CE	CE	
6. YEAR BOILER PLACED IN SERVICE	1963	1963	1965	1965	
7. REMAINING LIFE OF UNIT					
8. GENERATING CAPACITY (MW)					
RATED	400	400			
MAXIMUM CONTINUOUS			--------800---------		
PEAK					
9. FUEL CONSUMPTION:					
COAL OR OIL RATED Oil (BBL/HR)	568.1	568.1	--------1344---------		
Coal (Ton/HR) MAXIMUM CONTINUOUS	None	None	--------321---------		
Rated Gas	3580	3580	--------None---------		
10. ACTUAL FUEL CONSUMPTION					
GAS (1975) 10^6 FT^3	250.1	32.7	--------72.9---------		
OIL (1975) 10^3 BBL	3110.7	2487.8	--------7643.9-------		
11. HEAT RATE BTU/KWHR GAS					
COAL (1968)			--------9749---------		
OIL (1974)			--------9464---------		
12. WET OR DRY BOTTOM			Dry	Dry	
13. FLY ASH REINJECTION (YES OR NO)	No	No	No	No	
14. STACK HGT ABOVE GRADE (FT.)	515	515	--------515----------		
15. I.D. OF STACK AT TOP (INCHES)	170	170	--------288---------		

Notes:

	Boiler number				
	10	20	30		
16. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS					
MANUFACTURER					
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE: (GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER			Cott*		
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)			99/		
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)			4944		
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)			1,008,000		
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)			700		
17. EXCESS AIR: DESIGN/ACTUAL (%)	10	10	25		

Notes: * Cott - Research Cottrell, Inc.

	Boiler number				
	10	20	30		
18. FLUE GAS RATE (ACFM)					
@ 100% LOAD	656,000	656,000	4,300,000		
@ 75% LOAD					
@ 50% LOAD					
19. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	335	335	700		
@ 75% LOAD					
@ 50% LOAD					
20. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	119	119	105		
@ 75% LOAD					
@ 50% LOAD					
21. FLY ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD					
DISPOSAL COST ($/TON)					
22. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD					
DISPOSAL COST ($/TON)					
23. EXHAUST DUCT DIMENSIONS @ STACK					
24. ELEVATION OF TIE IN POINT TO STACK					
25. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)					

a) Identify source of values (test or estimate)

Notes:

E. I.D. FAN DATA	Boiler number				
1. MAXIMUM STATIC HEAD (IN. W.G.)					
2. WORKING STATIC HEAD (IN. W.G.)					

Notes:

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES)
2. YEARS STORAGE (ASH ONLY)
3. DISTANCE FROM STACK (FT.)
4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION
   a.
   b.
   c.
   d.
2. QUANTITY USED BY SEAM AND/OR MINE
   a.
   b.
   c.
   d.
3. ANALYSIS (19)
   HHV (BTU/LB)
   S (%)
   ASH (%)
   MOISTURE (%)
4. PPT PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA (1975)

1. TYPE
2. S CONTENT (%) 0.27
3. ASH CONTENT (%)
4. SPECIFIC GRAVITY
5. HHV (BTU/GAL) 144,241

I. NATURAL GAS HHV (BTU/FT^3) 1025

J. COST DATA

ELECTRICITY

FUEL: COAL GAS OIL

WATER

STEAM

TAXES ON A.P.C. EQUIPMENT: STATE SALES (No Sales Tax)

STATE PROPERTY TAX

K. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE?

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE?

L. ADDITIONAL INFORMATION

F.E.A. LETTER

M. OIL/GAS TO COAL CONVERSION DATA

1. HAS THE BOILER EVER BURNED COAL?

Boiler No.					
Yes or No.					

2. SYSTEM AVAILABILITY

2.1 COAL HANDLING

Boiler 30

	Yes	No
a. Is the system still installed?	☒	☐
b. Will it operate?	☒	☐

c. Of the following items which need to be replaced:

	Yes	No
Unloading equipment	☒	☐
Stack Reclaimer (Barge)	☐	☒
Bunkers	☒	☐
Conveyors	☒	☐
Scales	☒	☐
Coal Storage Area	☐	☒

2.2 FUEL FIRING

	Yes	No
a. Is the system still installed?	☒	☐
b. Will it operate?	☒	☐

c. Of the following items which need to be replaced:

	Yes	No
Pulverizers or Crushers	☒	☐
Feed Ducts	☒	☐
Fans	☒	☐
Controls	☒	☐

2.3 GAS CLEANING

	Yes	No
a. Is the system still installed?	☐	☐
b. Will it operate?	☐	☐

c. Of the following items which need to be replaced:

	Yes	No
Electrostatic Precipitator	☒	☐
Cyclones	☒	☐
Fly Ash Handling Equipment	☒	☐
Soot Blowers - Air Compressors	☒	☐
Wall deslaggers	☒	☐

2.4 ASH HANDLING

		Yes	No
a.	Is the system still installed?	☒	☐
b.	Will it operate?	☒	☐
c.	Of the following items which need to be replaced:		
	Bottom Ash Handling	☒	☐
	Ash Pond	☒	☐

N. SUPPLEMENTARY CONTROL SYSTEM DATA

1. DOES THE PLANT NOW HAVE A SUPPLEMENTAL CONTROL SYSTEM (SCS)? Yes ☐ No ☐

   If yes, attach a description of the system.

2. IS THE PLANT CAPABLE OF SWITCHING TO LOW SULFUR FUELS? Yes ☐ No ☐

   2.1 Storage capacity for low sulfur fuels (tons, bbls, days)

   2.2 Bunkers available for low sulfur coal storage? Yes ☐ No ☐

   2.3 Handling facilities available for low sulfur fuels Yes ☐ No ☐

   If yes, describe ____________________

   ____

   2.4 Time required to switch fuels and fire the low sulfur fuel in the boiler (hrs)?______

3. IS THE PLANT CAPABLE OF LOAD SHEDDING?

   If yes, discuss ____________________

   ____________________ Yes ☐ No ☐

4. IS THE PLANT CAPABLE OF LOAD SHIFTING?

   If yes, discuss ____________________

   ____________________ Yes ☐ No ☐

5. POWER PLANT MONITORING SYSTEM

   5.1 Existing system Yes ☐ No ☐

	Number	Type
a. Air quality instrumentation		
(1) Sulfur Oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulates		
- Intermittent	______	______
- Static	______	______
(3) Other (describe)__________		

   b. Meteorological instrumentation

   If yes, describe ____________________

   ____

   c. Is the monitoring data available? Yes ☐ No ☐

   d. Is the monitoring data reduced and analyzed? Yes ☐ No ☐

   e. Provide map of monitoring locations

5.2 Proposed system — Yes ☐ No ☐

If yes, describe and provide map ____________

____

a. Air monitoring instrumentation

		Number	Type
(1) Sulfur oxides	- Continuous	______	______
	- Intermittent	______	______
	- Static	______	______
(2) Suspended particulate			
	- Intermittent	______	______
	- Static	______	______

(3) Other (describe) ____________

b. Meteorological instrumentation

If yes, describe ____________

____

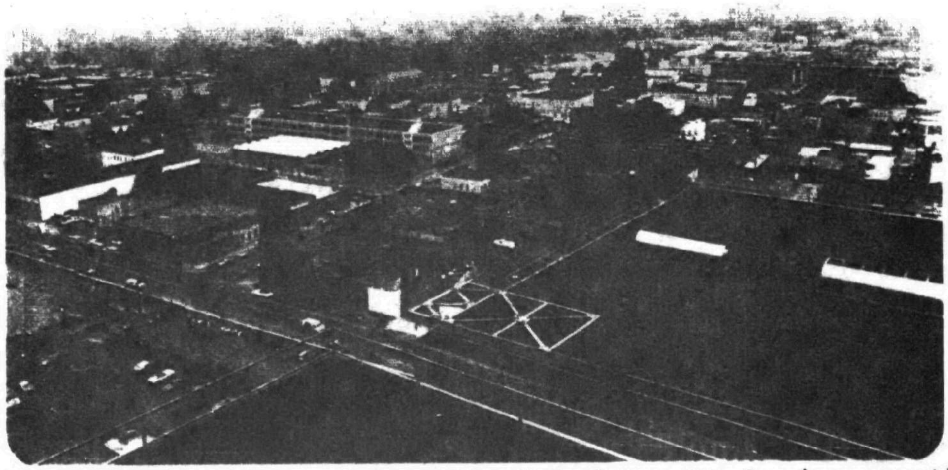


Photo No. 1 View from the roof of Boiler 30 facing northeast. The surrounding urbanized Queens area is shown across the center of the photograph.

Photo No. 2 View from the roof of Boiler 30 looking east. A portion of the ESP house is shown across the bottom of the photo. Part of Stack 30 is shown on the right side of the photograph.

Photo No. 3 View from the boiler house roof facing northwest. Turbines 4 through 11 are shown in the center of the photo. To their right are shown a fuel oil tank and two gas turbines. The Welfare Island Bridge is shown just left of center.

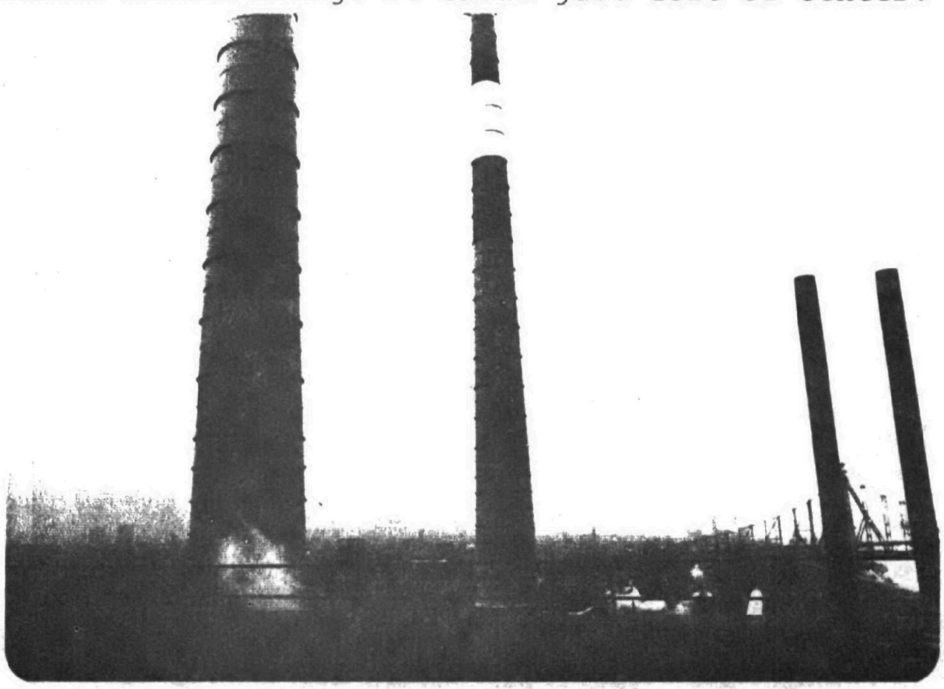


Photo No. 4 View from the roof of Boiler 30 looking south-southeast. Stacks 10 and 20 are shown in the center of the photo from right to left, respectively.

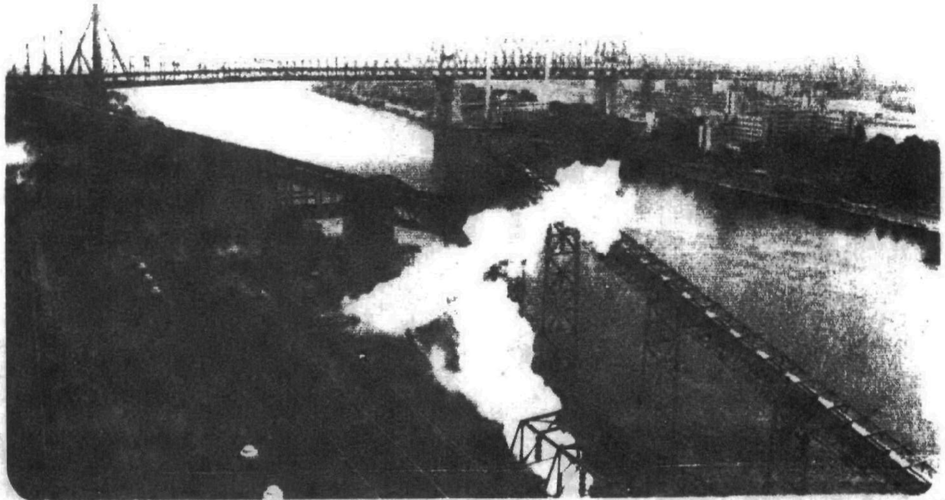


Photo No. 5 View from the boiler house roof facing south-southwest. The coal crusher house is shown in the center of the photo. To its right and left, respectively, are shown coal conveyors A and B. The top half of the photo shows the 59th Street Bridge crossing the East River.

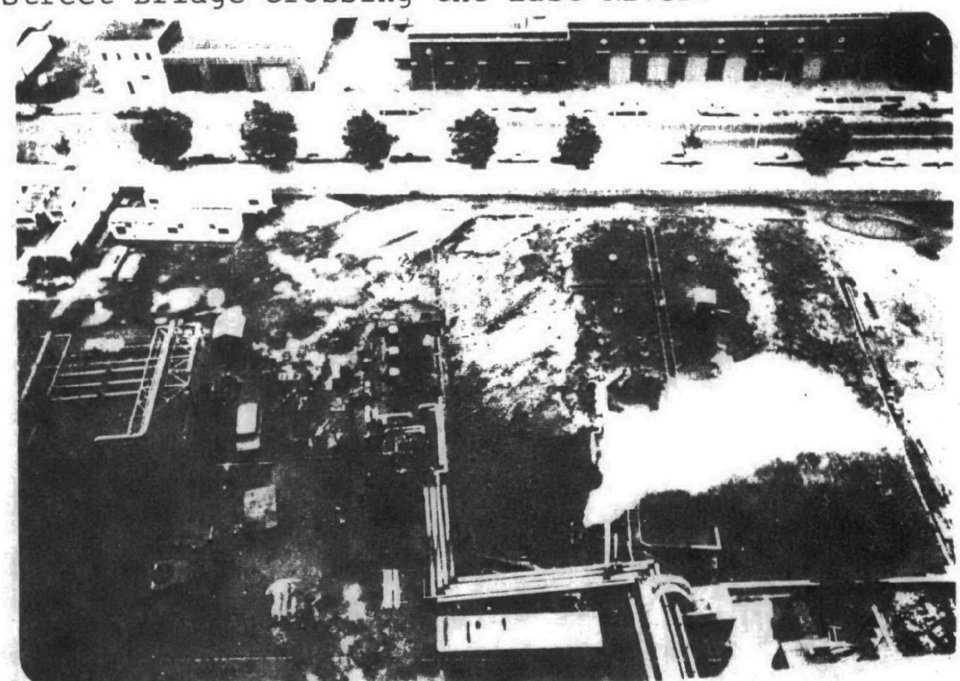


Photo No. 6 View from the roof of Boiler 20 facing east. Oil transfer pumps for Boilers 10 and 20 are shown just left of center. The natural gas meter and regulation station are shown left of the pumps.

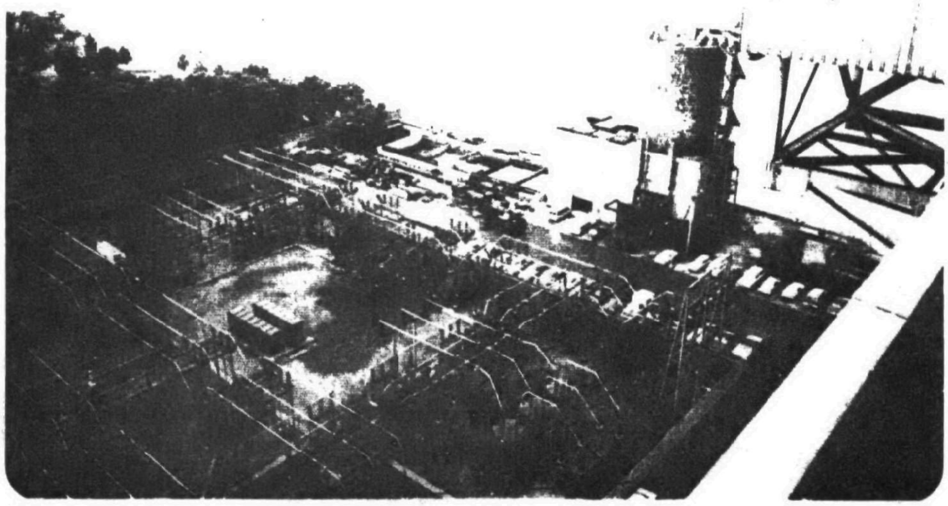


Photo No. 7 View from the boiler house roof looking southwest. The Vernon switch station is shown in the bottom left portion of the photo. The ash silo is shown just right of center.

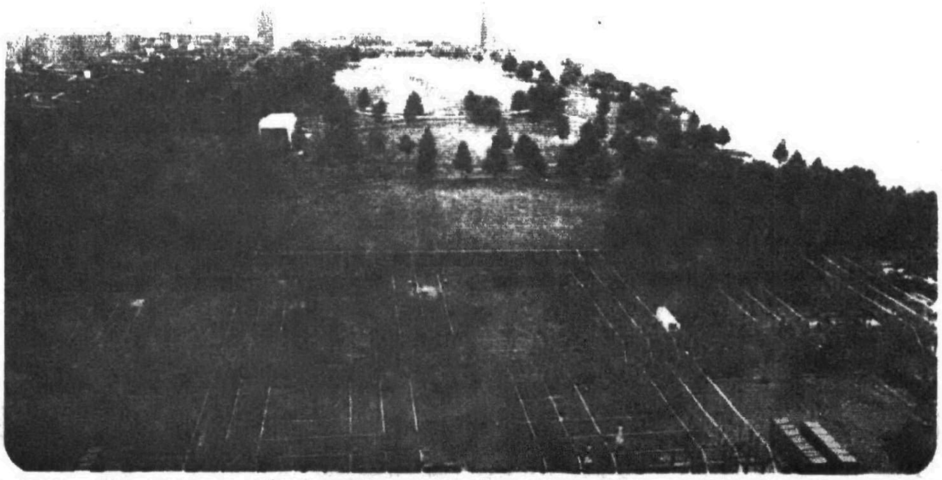


Photo No. 8 View from the roof of Boiler 10 facing south. Queensboro Park is shown in the center of the photograph. The switchyard and 59th Street Bridge are shown at the bottom and top of the photo, respectively.

Photo No. 9 View from ground level facing north. The coal unloading tower is shown in the center of the photo. Conveyor A is shown rising upward at left.

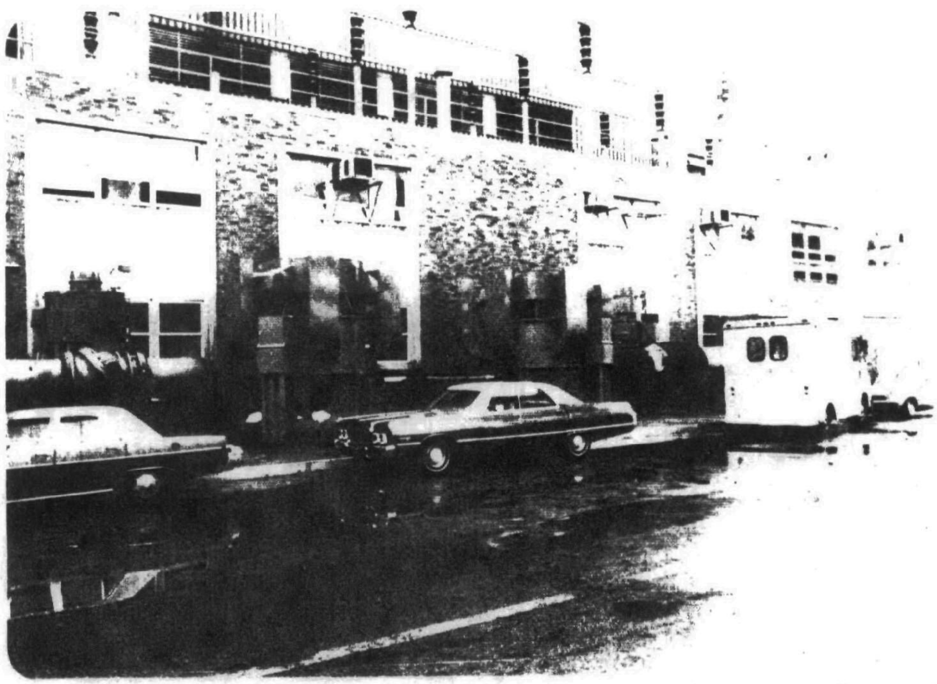


Photo No. 10 View from ground level looking south-southeast. Cooling water circulating pumps are shown in the center of the photo.

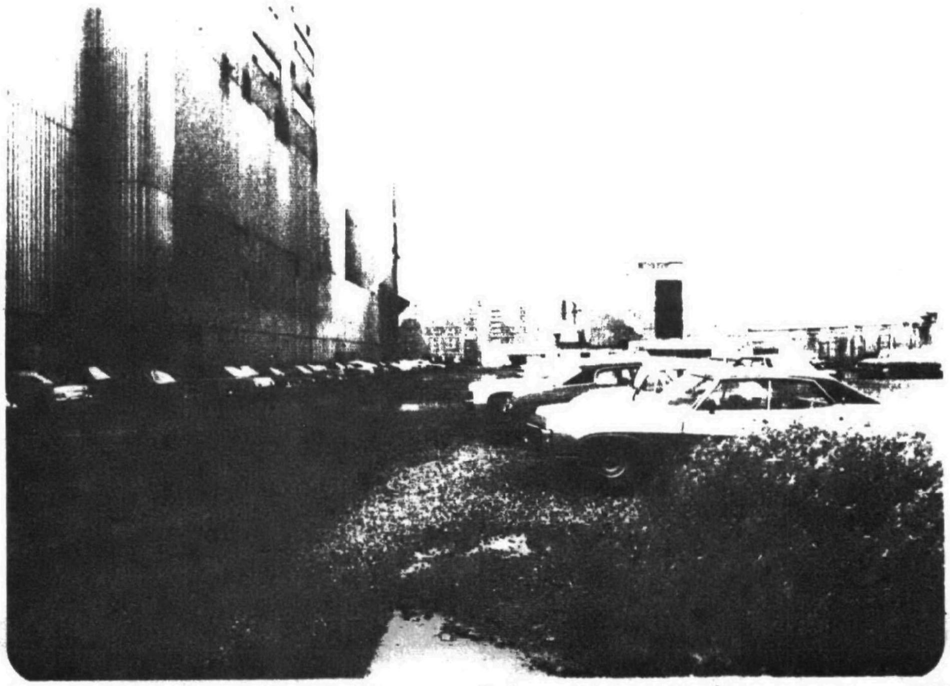


Photo No. 11 View from the parking lot facing west. The Ravenswood power plant is at left and its steam plant is shown right of center. The steam plant's two stacks are also shown.

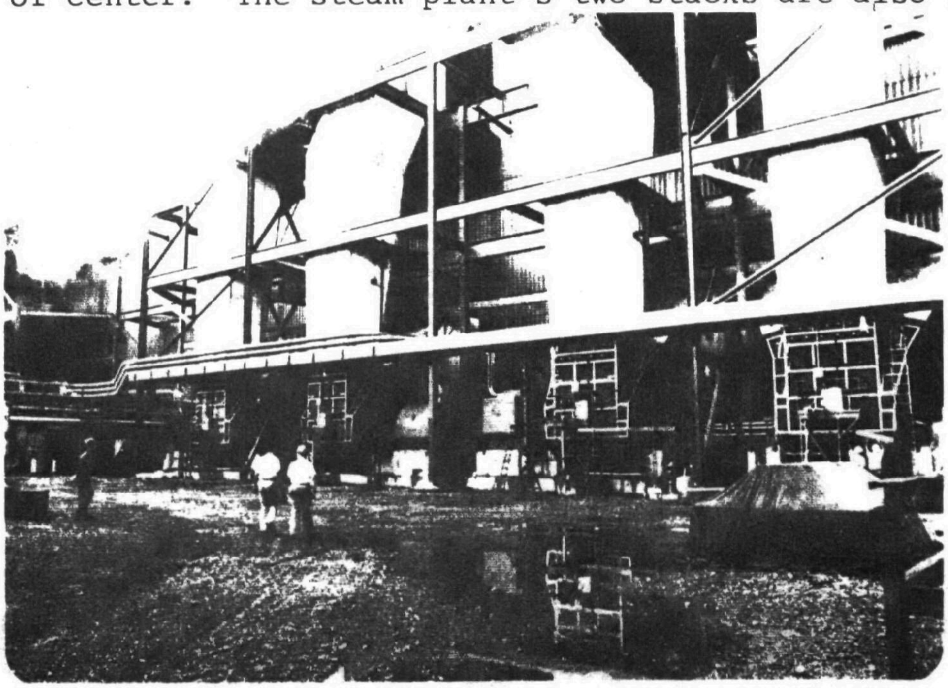


Photo No. 12 View from ground level looking southwest. The I.D. fan installations for Boilers 10 and 20 are shown respectively, from left to right across the center of the photograph.

TABLE O-1. ESTIMATED CAPITAL COST OF A SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILER 30 AT THE RAVENSWOOD POWER PLANT (1978)

Direct Costs		
A.	Soda Ash Preparation	
	Storage silos	$ 89,000
	Vibrating feeders	6,000
	Storage tanks	32,000
	Agitators	26,000
	Pumps and motors	2,000
	Total A =	$ 155,000
B.	SO_2 Scrubbing	
	Absorbers	$20,570,000
	Fans and motors	2,275,000
	Pumps and motors	602,000
	Reheaters	3,595,000
	Soot blowers	2,608,000
	Ducting	10,690,000
	Valves	1,674,000
	Total B =	$42,014,000
C.	Purge Treatment	
	Refrigeration unit	$ 585,000
	Heat exchangers	87,000
	Tanks	101,000
	Dryer	32,000
	Elevator	15,000
	Pumps and motors	493,000
	Centrifuge	1,171,000
	Crystallizer	1,405,000
	Storage silo	89,000
	Feeder	6,000
	Total C =	$ 3,984,000

(continued)

TABLE O-1 (continued)

D.	Regeneration		
	Pumps and motors		$ 317,000
	Evaporators and reboilers		5,268,000
	Heat exchangers		690,000
	Tanks		77,000
	Stripper		154,000
	Blower		225,000
		Total D =	$ 6,731,000
E.	Particulate Removal		
	Venturi scrubber		$ 9,030,000
	Tanks		262,000
	Pumps and motors		2,642,000
		Total E =	$ 11,934,000
	Total direct costs = A + B + C + D + E = F =		$ 64,818,000
Indirect Costs			
	Interest during construction		$ 6,482,000
	Field labor and expenses		6,482,000
	Contractor's fee and expenses		3,241,000
	Engineering		6,482,000
	Freight		810,000
	Offsite		1,944,000
	Taxes		000
	Spares		324,000
	Allowance for shakedown		3,241,000
	Acid plant		2,498,000
		Total indirect costs G =	$ 31,504,000
		Contingency H =	19,264,000
		Total = F + G + H =	$115,586,000
		Coal conversion cost	863,000
		Grand total	$116,449,000
		$/kW	145.56

TABLE O-2. ESTIMATED ANNUAL OPERATING COST OF A SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILER 30 AT THE RAVENSWOOD POWER PLANT (1978)

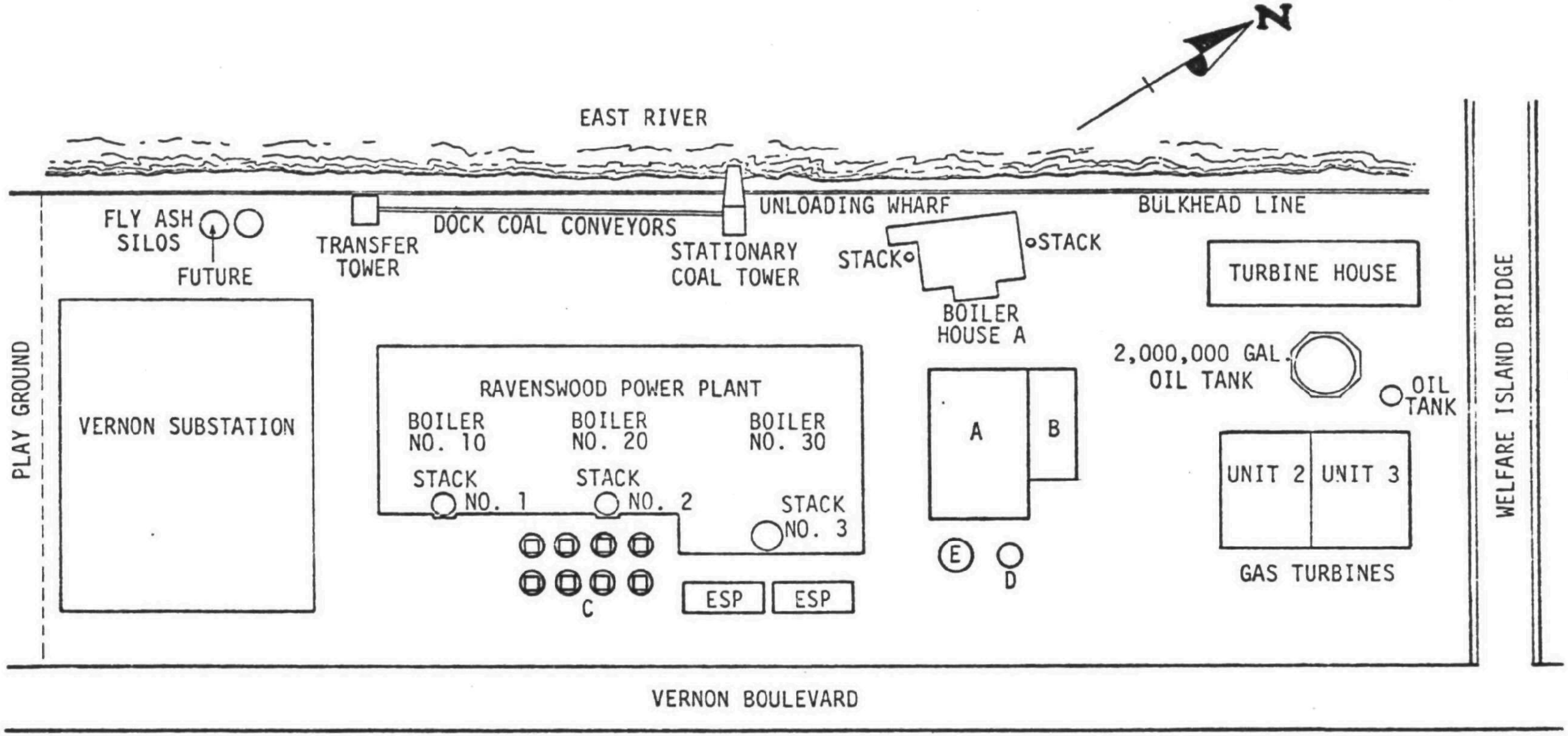
	Quantity	Unit Cost	Annual Cost
Raw Materials			
Soda Ash	0.84 tons/h	\$90.36/ton	\$ 421,000
Utilities			
Process water	4168 gal/min	$\$0.66/10^3$ gal	912,000
Cooling water	16.5×10^3 gal/min	$\$0.01/10^3$ gal	56,000
Electricity	19078 kW	33.3 mills/kWh	3,504,000
Reheat steam	137×10^6 Btu/h	$\$1.696/10^6$ Btu	1,278,000
Process steam	234×10^6 Btu/h	$\$1.699/10^6$ Btu	2,193,000
Operation Labor			
Direct labor	4 men/day	\$10.67/man-hour	374,000
Supervision	15% of direct labor		56,000
Maintenance			
Labor and materials	4% of fixed investment		4,623,000
Supplies	15% of labor and materials		694,000
Overhead			
Plant	50% of operating and maintenance		2,874,000
Payroll	20% of operating labor		86,000
Fixed Costs			
Depreciation	(3.70%)		
Interim replacement	(0.35%)		
Insurance	(0.30%)		
Taxes	(4.00%), Σ = 19.55% of fixed investment		
Capital cost	(11.20%)		
Total fixed cost			22,597,000
Total cost			\$ 39,668,000
Credits (byproducts)			
Sulfuric acid	11.64 tons/h	\$58.41/ton	(3,754,000)
Na_2SO_4	0.84 tons/h	\$71.63/ton	(334,000)
Total byproduct credits			\$ (4,088,000)
Fuel credit			(26,149,000)
Net annual cost			\$ 9,431,000
Mills/kWh			2.13

Table O-3. RETROFIT EQUIPMENT AND FACILITIES FOR THE SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILER 30 AT THE RAVENSWOOD POWER PLANT

Module Description	Number Required	Size/Capacity
Absorbers	8	100 MW capacity unit
Flue gas fans	8	Scaled to train size
Na_2CO_3 storage	1	605 tons (30-day storage)
Na_2CO_3 preparation	1	1680 lb/hr, Na_2CO_3
SO_2 regeneration	1	12,850 lb/hr, SO_2
Purge treatment	1	1680 lb/hr, Na_2SO_4
Sulfuric acid plant	1	146 tons/day, H_2SO_4

Table O-4. RETROFIT EQUIPMENT DIMENSIONS REQUIRED FOR THE SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILER 30 AT THE RAVENSWOOD POWER PLANT

Item	Number required	Dimensions, ft
Na_2CO_3 storage	1	20 diam x 45 high
Absorber feed surge tank	1	40 diam x 40 high
Turbulent contact absorbers	8	45 high x 15 wide x 40 long
Regeneration plant	1	65 x 180
Purge treatment plant	1	65 x 190
Acid plant	1	75 x 155



A PURGE TREATMENT AND SO_2 REGENERATION
B ACID
C SCRUBBERS
D STORAGE SILO
E SOLUTION TANK

Figure O-1. Site plan showing possible locations of major components for the sodium solution regenerable system for Boiler 30 at the Ravenswood power plant.

TABLE O-5. ESTIMATED CAPITAL COST OF A LIMESTONE SCRUBBING SYSTEM FOR BOILER 30 AT THE RAVENSWOOD POWER PLANT (1978)

Direct Cost			
A.	Limestone Preparation		
	Conveyors		$ 453,000
	Storage silo		100,000
	Ball mills		724,000
	Pumps and motors		206,000
	Storage tanks		171,000
		Total A =	$ 1,654,000
B.	Scrubbing		
	Absorbers		$16,557,000
	Fans and motors		2,527,000
	Pumps and motors		1,254,000
	Tanks		992,000
	Reheaters		3,595,000
	Soot blowers		978,000
	Ducting and valves		10,930,000
		Total B =	$36,833,000
C.	Sludge Disposal		
	Clarifiers		$ 346,000
	Vacumm filters		484,000
	Tanks and mixers		12,000
	Fixation chemical storage		33,000
	Pumps and motors		108,000
	Sludge pond		2,103,000
	Mobile equipment		64,000
		Total C =	$ 3,150,000

(continued)

TABLE O-5 (continued)

D.	Particulate Removal		
	Venturi scrubber	$	9,030,000
	Tanks		265,000
	Pumps and motors		348,000
	Total D =	$	9,643,000
	Total direct costs = A + B + C + D = E =	$	51,280,000
Indirect Costs			
	Interest during construction	$	5,128,000
	Field overhead		5,128,000
	Contractor's fee and expenses		2,564,000
	Engineering		5,128,000
	Freight		641,000
	Offsite		1,538,000
	Taxes		000
	Spares		256,000
	Allowance for shakedown		2,564,000
	Total indirect costs F =	$	22,947,000
	Contingency G =		14,845,000
	Total = E + F + G =	$	89,072,000
	Coal conversion costs		863,000
	Grand total	$	89,935,000
	$/kW		112.42

TABLE O-6. ESTIMATED ANNUAL OPERATING COST OF A LIMESTONE SCRUBBING SYSTEM FOR BOILER 30 AT THE RAVENSWOOD POWER PLANT (1978)

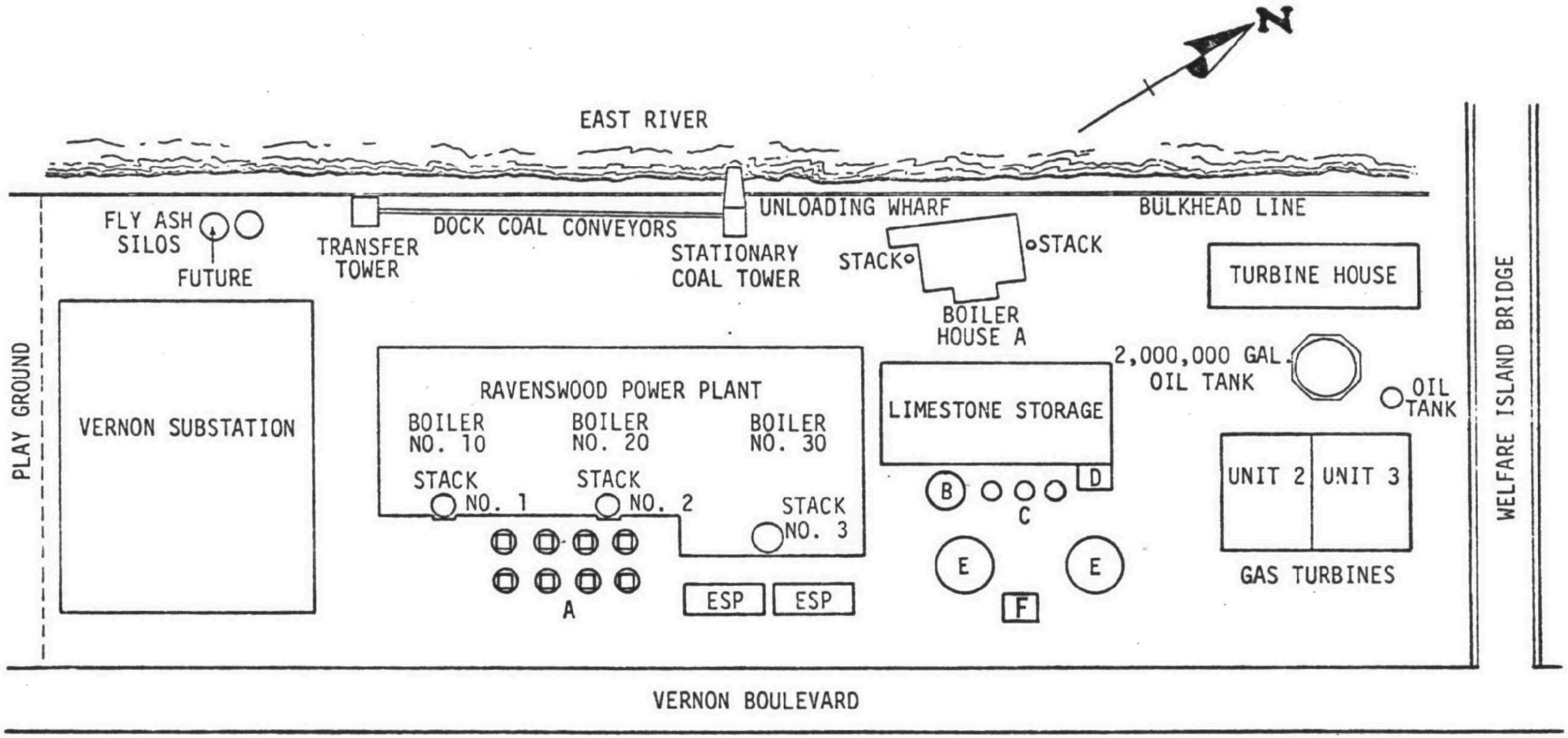
	Quantity	Unit Cost	Annual Cost
Raw Materials			
Limestone	16.2 tons/h	$16.81/ton	$ 1,510,000
Fixation chemicals	67.0 tons/h	$2.20/ton	817,000
Utilities			
Water	290 gal/min	$0.66/10^3 gal	64,000
Electricity	15,633 kW	33.3 mills/kWh	2,872,000
Fuel for reheat	136.5 x 10^6 Btu/h	$1.696/10^6 Btu	1,278,000
Operating Labor			
Direct labor	3 men/day	$10.67/man-hour	281,000
Supervision	15% of direct labor		42,000
Maintenance			
Labor and materials	4% of fixed investment		3,563,000
Supplies	15% of labor and material		534,000
Overhead			
Plant	50% of operation and maintenance		2,210,000
Payroll	20% of operating labor		65,000
Trucking			
Bottom/fly ash and sludge removal			12,242,000
Fixed Costs			
Depreciation	(3.70%)		
Interim replacement	(0.35%), Σ = 19.55% of fixed investment		
Insurance	(0.30%)		
Taxes	(4.00%)		
Capital cost	(11.20%)		
Total fixed charges			17,414,000
Total cost			$42,892,000
Fuel credit			(26,149,000)
Net annual cost			$16,743,000
Mills/kWh			3.79

Table O-7. RETROFIT EQUIPMENT AND FACILITIES REQUIRED FOR THE LIMESTONE SCRUBBING SYSTEM FOR BOILER 30 AT THE RAVENSWOOD POWER PLANT

Module Description	Number Required	Size/Capacity
Limestone storage	1	11,700 tons (30 day storage)
Limestone slurry	1	16.2 ton/hr limestone
Turbulent contact absorbers	8	100 MW unit/s
Flue gas fans	8	Scaled to train size

Table O-8. RETROFIT EQUIPMENT DIMENSIONS REQUIRED FOR THE LIMESTONE SCRUBBING SYSTEM FOR BOILER 30 AT THE RAVENSWOOD POWER PLANT

Item	Number Required	Dimensions, ft
Limestone storage pile	1	115 wide x 170 long
Limestone silos	3	17 diam x 38 high
Limestone slurry tanks	1	60 diam x 20 high
Ball mill building	1	40 x 40
Turbulent contact absorbers	8	45 high x 15 wide x 30 long
Clarifiers	2	75 diam x 20 high
Vacuum filter building	1	40 x 40



A SCRUBBERS
B SLURRY TANK
C LIMESTONE SILOS
D BALL MILL BUILDING
E CLARIFIER
F VACUUM FILTER BUILDING

Figure O-2. Site plan showing possible locations of major components for the limestone system for Boiler 30 at the Ravenswood power plant.

APPENDIX P

RIDGELAND POWER PLANT

CONTENTS

FIGURES

TABLES

TABLES (continued)

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Commonwealth Edison
2. MAIN OFFICE: P.O. Box 767
3. RESPONSIBLE OFFICER: J. P. McCluskey
4. POSITION: Director of Environmental Affairs
5. PLANT NAME: Ridgeland Station
6. PLANT LOCATION: 4300 South Ridgeland Avenue
7. RESPONSIBLE OFFICER AT PLANT LOCATION: T. F. McKeon
8. POSITION: Station Superintendent
9. POWER POOL MAIN

DATE INFORMATION GATHERED: July 27, 1976

PARTICIPANTS IN MEETING:

J. P. McClusky	Commonwealth Edison Company
W. L. Ramsey	Commonwealth Edison Company
Mike Trykoski	Commonwealth Edison Company
Walter N. Kozlowski	Commonwealth Edison Company
Lee Hermansen	Commonwealth Edison Company
Ron Cook	Commonwealth Edison Company
A. O. Courtney	Commonwealth Edison Company
Eugene H. Reinstein	Ishan, Lincoln, and Beale
Thomas C. Ponder, Jr.	PEDCo Environmental, Inc.
N. David Noe	PEDCo Environmental, Inc.
Richard T. Price	PEDCo Environmental, Inc.

	Boiler number				
	1	2	3	4	5
B. ATMOSPHERIC EMISSIONS					
1. PARTICULATE EMISSIONS[a]					
LB/MM BTU	.06	.06	.06	.06	.06
GRAINS/ACF	-	-	-	-	-
LB/HR (FULL LOAD)			326 (all boilers)		
TONS/YEAR (1975)			824 (all boilers)		
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION					
REGULATION & SECTION NO.		Cook County Ordinance 6.2-2(b) (all boilers)			
LB/MM BTU			0.1 lb/MMBTU (all boilers)		
OPACITY, PERCENT			30% (6.1-1(b)) (all boilers)		
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.			NA (all boilers)		
LB/MM BTU			NA (all boilers)		
3. SO_2 EMISSIONS[a] (Oil)					
LB/MM BTU			0.90 (all boilers)		
LB/HR (FULL LOAD)			4890 (all boilers)		
TONS/YEAR ( )			12,350 (all boilers)		
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.		Cook County Ordinance 6.31(d)(2)(i) (all boilers)			
LB/MM BTU (liquid fuel)		1.0 (all boilers)			
LB/MM BTU (solid fuel)		1.8 (all boilers)			
b) FUTURE REQUIREMENT (DATE:)			NA (all boilers)		
REGULATION & SECTION NO.					
LB/MM BTU			NA (all boilers)		

a) Identify whether results are from stack tests or estimates

RIDGELAND POWER PLANT

	Boiler number				
	6				
B. ATMOSPHERIC EMISSIONS					
1. PARTICULATE EMISSIONS[a]					
LB/MM BTU	.06				
GRAINS/ACF	-				
LB/HR (FULL LOAD)	-------				
TONS/YEAR ( )	-------				
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION					
REGULATION & SECTION NO.	-------				
LB/MM BTU	-------				
OPACITY, PERCENT	-------				
b) FUTURE REQUIREMENT (DATE:) REGULATION & SECTION NO.	-------				
LB/MM BTU	-------				
3. SO_2 EMISSIONS[a] LB/MM BTU	-------				
LB/HR (FULL LOAD)	-------				
TONS/YEAR ( )	-------				
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.	-------				
LB/MM BTU	-------				
LB/MM BTU	-------				
b) FUTURE REQUIREMENT (DATE:) REGULATION & SECTION NO.	-------				
LB/MM BTU					

a) nt wh er ul are om ick st e nai

C. SITE DATA

1. U.T.M. COORDINATES ______________________

2. ELEVATION ABOVE MEAN SEA LEVEL (FT) ______________________

3. SOIL DATA: BEARING VALUE ______________________

   PILING NECESSARY Yes

4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA

5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE) 128.0 ft.*

6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): N/A

* Height of stack: 213 ft.

D. BOILER DATA

	Boiler number 1	2	3	4	5
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK	Floating	Floating	Floating	Floating	Floating
2. TOTAL HOURS OPERATION (19 75)	6302	5129	7134	6666	3925
3. AVERAGE CAPACITY FACTOR (19 75)	52.7	47.8	56.1	51.8	31.2
4. SERVED BY STACK NO.	1	2	3	4	5
5. BOILER MANUFACTURER [a]	B&W	B&W	B&W	B&W	B&W
6. YEAR BOILER PLACED IN SERVICE	1951	1951	1950	1950	1953
7. REMAINING LIFE OF UNIT [b]	N/A	N/A	N/A	N/A	N/A
8. GENERATING CAPACITY (MW) ~~RATED~~ Summer Gross	Unit 1 166	-	Unit 2 166	-	Unit 3 151
Summer Net	152	-	152	-	137
PEAK					
9. FUEL CONSUMPTION:[c] Gas 10^3 ft^3/hr	821.1	821.1	821.1	821.1	1423
COAL OR OIL RATED Coal (TPH)	42.7	42.7	42.7	42.7	74
Oil (BPH) MAXIMUM CONTINUOUS	136.3	136.3	136.3	136.3	236.2
PEAK					
10. ACTUAL FUEL CONSUMPTION Gas (10^6 ft^3/yr) (1975)	Boiler 1 and 2 17.6		Boiler 3 and 4 20.3		548.8
COAL (TPY) (19 75)	None		None		None
OIL (BPY) (19 75)	1219.3		1488.6		599.2
11. HEAT RATE BTU/KWHR GAS					
COAL[d]	10,861	11,216	9,859	9,737	
OIL	11,376 BTU/NKWH - Station Total				
12. WET OR DRY BOTTOM	Wet	Wet	Wet	Wet	Wet
13. FLY ASH REINJECTION (YES OR NO)	No	No	No	No	No
14. STACK HGT ABOVE GRADE (FT.)	213	213	213	213	213
15. I.D. OF STACK AT TOP (INCHES)	96	96	96	96	118

Notes:
[a] The Babcock & Wilcox Company.
[b] Plant - 1986.
[c] Data is design data at 100% rating.
[d] Station avg. - 10,623 BTU/kWh(net) on [illegible]

D. BOILER DATA

	Boiler number				
	6				
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK	-------				
2. TOTAL HOURS OPERATION (1975)	6012				
3. AVERAGE CAPACITY FACTOR (1975)	49.8				
4. SERVED BY STACK NO.	6				
5. BOILER MANUFACTURER [a]	B&W				
6. YEAR BOILER PLACED IN SERVICE	1955				
7. REMAINING LIFE OF UNIT [b]	N/A				
8. GENERATING CAPACITY (MW)	Unit 4 146				
;	132				
PEAK					
9. FUEL CONSUMPTION: [c]	1423				
COAL OR OIL (TPH) OR (GPH) RATED Coal (TPH) Oil (BPH) MAXIMUM CONTINUOUS	74 236.2				
PEAK					
10. ACTUAL FUEL CONSUMPTION Gas (10^3 MCF) (1975) COAL (TPY) (1975)	51.2 None				
OIL (BPY) (1975)	1113.8				
11. HEAT RATE BTU/KWHR GAS					
COAL					
OIL					
12. WET OR DRY BOTTOM	Wet				
13. FLY ASH REINJECTION (YES OR NO)	No				
14. STACK HGT ABOVE GRADE (FT.)	213				
15. I.D. OF STACK AT TOP (INCHES)	118				

Notes:

	Boiler number				
	1	2	3	4	5
16. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS					
MANUFACTURER	None	None	None	None	None
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE: (GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR MANUFACTURER	(1) Res. Cott	(1) Res. Cott	(1) Res. Cott	(1) Res. Cott	(1) Res. Cott
TYPE	(2) E	(2)E	(2)E	(2) E	(2) E
EFFICIENCY: DESIGN/ACTUAL (%)	98%	98%	98%	98%	90%
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS	4	4	4	4	4
TOTAL PLATE AREA (FT^2)	25,200	25,200	25,200	25,200	60,500
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)	385	385	385	385	334
17. EXCESS AIR: DESIGN/ACTUAL (%)	18	18	18	18	10

Notes: (1) Res. Cott - Research Cottrell, Inc.
(2) E - Electrostatic Precipitator

	Boiler number				
	6				
16. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS					
MANUFACTURER	None				
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE: (GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER	(1) Res. Cott				
TYPE	(2) E				
EFFICIENCY: DESIGN/ACTUAL (%)	90%				
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS	8				
TOTAL PLATE AREA (FT^2)	600,500				
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)	334				
17. EXCESS AIR: DESIGN/ACTUAL (%)	10				

Notes:
(1) Res. Cott - Research Cottrell
(2) E - Electrostatic Precipitator

	Boiler number				
	1	2	3	4	5
18. FLUE GAS RATE (ACFM)					
@ 100% LOAD (Design)	384,000	384,000	384,000	384,000	546,000
@ 75% LOAD	288,000	288,000	288,000	288,000	409,500
@ 50% LOAD	192,000	192,000	192,000	192,000	273,000
19. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD (High)	335 (2)	335 (2)	335 (2)	335 (2)	350 (2)
@ 75% LOAD	310 (2)	310 (2)	310 (2)	310 (2)	310 (2)
@ 50% LOAD	285 (2)	285 (2)	285 (2)	285 (2)	275 (2)
20. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	127.4 (2)	127.4 (2)	127.4 (2)	127.4 (2)	119.9 (2)
@ 75% LOAD	95.6 (2)	95.6 (2)	95.6 (2)	95.6 (2)	89.9 (2)
@ 50% LOAD	63.7 (2)	63.7 (2)	63.7 (2)	63.7 (2)	60.0 (2)
21. FLY ASH: TOTAL COLLECTED (TONS/YEAR)					
DISPOSAL METHOD	----------	----------	500 tons	----------	----------
DISPOSAL COST ($/TON)	----------	----------	$66,000 total	----------	----------
22. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR)					
DISPOSAL METHOD[b]	None				
DISPOSAL COST ($/TON)					
23. EXHAUST DUCT DIMENSIONS @ STACK	(See attached drawings)				
24. ELEVATION OF TIE IN POINT TO STACK					
25. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)					

a) Identify source of values (test[1] or estimate[2])

Notes: [b]Waste Water Treatment.

	Boiler number				
	6				
18. FLUE GAS RATE (ACFM)					
@ 100% LOAD	546,000				
@ 75% LOAD	409,500				
@ 50% LOAD	273,000				
19. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	(2) 350				
@ 75% LOAD	310 (2)				
@ 50% LOAD	275 (2)				
20. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	119.9(2)				
@ 75% LOAD	39.9(2)				
@ 50% LOAD	60.0(2)				
21. FLY ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD	-------				
DISPOSAL COST ($/TON)	-------				
22. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD	None				
DISPOSAL COST ($/TON)					
23. EXHAUST DUCT DIMENSIONS @ STACK	(See attached drawings)				
24. ELEVATION OF TIE IN POINT TO STACK					
25. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)					

a) Identify source of values (test (1) or estimate (2))

Notes:

E. I.D. FAN DATA

	Boiler number				
	1	2	3	4	5
1. MAXIMUM STATIC HEAD (IN. W.G.)	[1] 16	[1] 16	[1] 16	[1] 16	[2] 18.4
2. WORKING STATIC HEAD (IN. W.G.)	14.5	14.5	14.5	14.5	12.9

Notes: [1] Based on 700,000 lb/hr. steam
[2] Based on 1,100,000 lb/hr. steam

E. I.D. FAN DATA	Boiler number				
	6				
1. MAXIMUM STATIC HEAD (IN. W.G.)	(2) 18.4				
2. WORKING STATIC HEAD (IN. W.G.)	12.9				

Notes:

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES) None
2. YEARS STORAGE (ASH ONLY)
3. DISTANCE FROM STACK (FT.)
4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

Coal Analysis (1955):

Ash - 10.8% by wt (as received); 12.2% (dry)
Moisture - 14.0% by wt
Sulfur - 4.4% by wt (as received)
BTU/lb - 10,500 as received); 12,400 (dry); 14,000 (moisture and ash free)

(1) per our latest survey of January 1976... The disposal area is 56.6% filled. Assuming present fuel, 86 years storage remain.

(2) Distance from Stack #1: 500 ft.
Distance from Stack #6: 950 ft.

H. FUEL OIL DATA (1975)

1. TYPE Residual
2. S CONTENT (%) 0.8
3. ASH CONTENT (%) 0.1
4. SPECIFIC GRAVITY N/A
5. HHV (BTU/GAL) 147,886

I. NATURAL GAS HHV (BTU/FT^3) 1034

J. COST DATA

ELECTRICITY

FUEL: COAL GAS OIL

WATER

STEAM

TAXES ON A.P.C. EQUIPMENT: STATE SALES Yes, Exempt

STATE PROPERTY TAX Not Exempt.

K. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE?

NORMAL LOAD ON PLANT SUBSTATION? Will have to add additional buses.

VOLTAGE AT WHICH POWER IS AVAILABLE?

L. ADDITIONAL INFORMATION

F.E.A. LETTER

M. OIL/GAS TO COAL CONVERSION DATA

1. HAS THE BOILER EVER BURNED COAL?

Boiler No.	1,2,3,4,5,6,				
Yes or No.	Yes				

2. SYSTEM AVAILABILITY

2.1 COAL HANDLING

	Yes	No
a. Is the system still installed?	☒	☐
b. Will it operate?	☐	☒

c. Of the following items which need to be replaced:

	Yes	No
Unloading equipment	☒	☐
Stack Reclaimer	☒	☐
Bunkers	☐	☒
Conveyors	☒	☐
Scales	☒	☐
Coal Storage Area	☒	☐

2.2 FUEL FIRING

	Yes	No
a. Is the system still installed?	☒	☐
b. Will it operate?	☐	☒

c. Of the following items which need to be replaced:

	Yes	No
Pulverizers or Crushers	☒	☐
Feed Ducts	☒	☐
Fans	☐	☒
Controls	☒	☐

2.3 GAS CLEANING

	Yes	No
a. Is the system still installed?	☒	☐
b. Will it operate?	☒	☐

c. Of the following items which need to be replaced:

	Yes	No
Electrostatic Precipitator	☒	☐
Cyclones	☐	☒
Fly Ash Handling Equipment	☒	☐
Soot Blowers - Air Compressors	☒	☐
Wall deslaggers	☐	☒

Not Adequate For Coal Firing Under Current Environmental Standards

2.4 ASH HANDLING

		Yes	No
a.	Is the system still installed?	☒	☐
b.	Will it operate?	☐	☒
c.	Of the following items which need to be replaced:		
	Bottom Ash Handling	☒	☐
	Ash Pond	☒	☐

N. SUPPLEMENTARY CONTROL SYSTEM DATA

1. DOES THE PLANT NOW HAVE A SUPPLEMENTAL CONTROL SYSTEM (SCS)? Yes [ ] No [x]

   If yes, attach a description of the system.

2. IS THE PLANT CAPABLE OF SWITCHING TO LOW SULFUR FUELS? Yes [ ] No [ ]

   2.1 Storage capacity for low sulfur fuels (tons, bbls, days)

   2.2 Bunkers available for low sulfur coal storage? Yes [ ] No [ ]

   2.3 Handling facilities available for low sulfur fuels Yes [ ] No [ ]

   If yes, describe ______________________

   ____

   2.4 Time required to switch fuels and fire the low sulfur fuel in the boiler (hrs)?______

3. IS THE PLANT CAPABLE OF LOAD SHEDDING?

   If yes, discuss ______________________

   ______________________________ Yes [ ] No [x]

4. IS THE PLANT CAPABLE OF LOAD SHIFTING?

   If yes, discuss ______________________

   ______________________________ Yes [x] No [ ]

5. POWER PLANT MONITORING SYSTEM

   5.1 Existing system Yes [ ] No [x]

   a. Air quality instrumentation

	Number	Type
(1) Sulfur Oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulates		
- Intermittent	______	______
- Static	______	______
(3) Other (describe)____________		

   b. Meteorological instrumentation

   If yes, describe ______________

   ____

   c. Is the monitoring data available? Yes [ ] No [ ]

   d. Is the monitoring data reduced and analyzed? Yes [ ] No [ ]

   e. Provide map of monitoring locations

5.2 Proposed system Yes [ ] No [x]

If yes, describe and provide map ______

______

a. Air monitoring instrumentation

		Number	Type
(1) Sulfur oxides	- Continuous	____	____
	- Intermittent	____	____
	- Static	____	____
(2) Suspended particulate	- Intermittent	____	____
	- Static	____	____

(3) Other (describe) ______

b. Meteorological instrumentation

If yes, describe ______

______

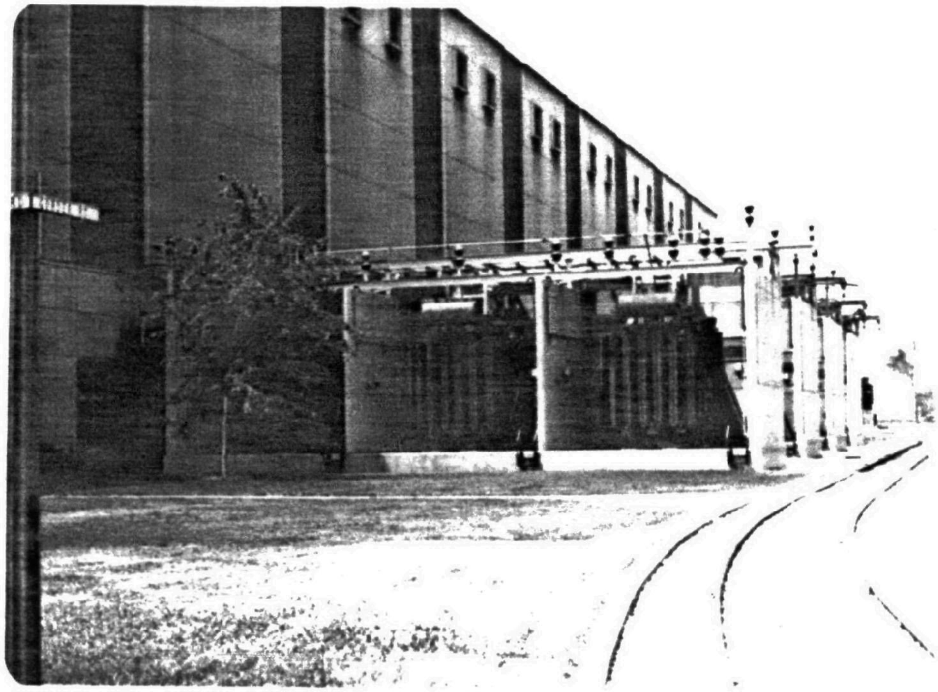


Photo No. 1 View from ground level facing southwest. The northern portion of the plant is shown. Two of the 69 kV transformers are in clear view in the center of the photograph.

Photo No. 2 View from the roof of Boiler 1 looking east. The top left of the photo shows the industrialized surrounding area, the center shows an ash pond, and the bottom of the photo shows rail lines.

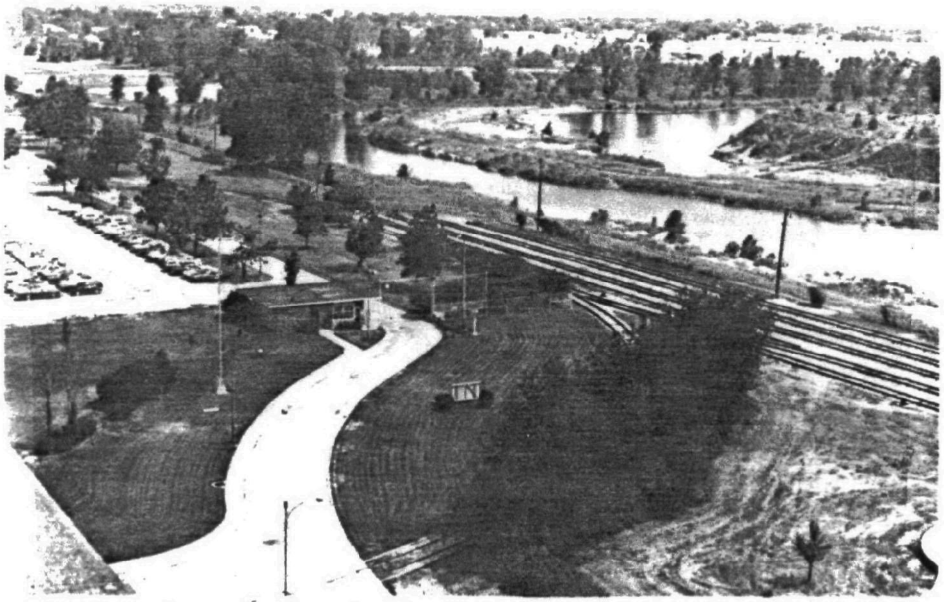


Photo No. 3 View from the boiler house roof facing north. The gate house and road leading into the plant are shown in the bottom left portion of the photo.

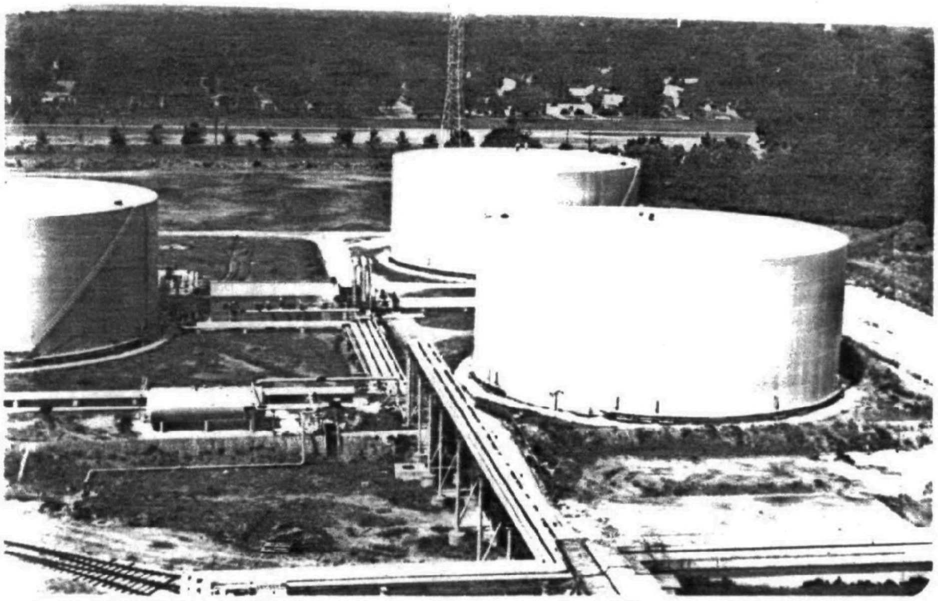


Photo No. 4 View from the roof of Boiler 6 looking west. A portion of the plant's oil storage tank area is shown. The densely wooded surrounding area is shown in the background.

Photo No. 5 View from the roof of Boiler 6 facing southwest. Part of the coal storage area is shown in the bottom left portion of the photograph. A rail spur line is shown leading toward the plant.

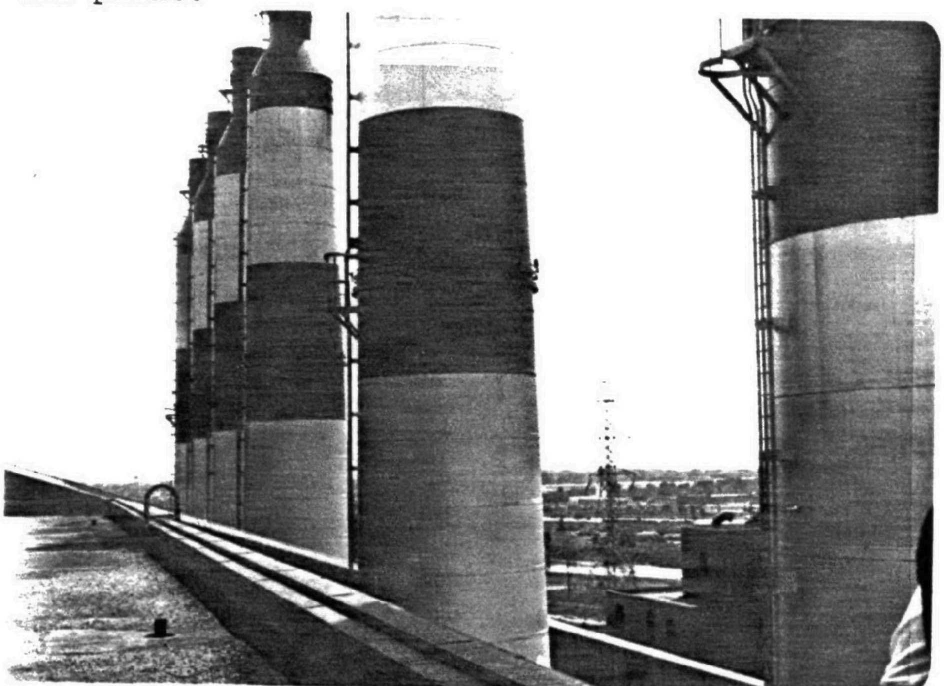


Photo No. 6 View from the roof of Boiler 6 looking southeast. Stacks 1 through 6 are shown from left to right.

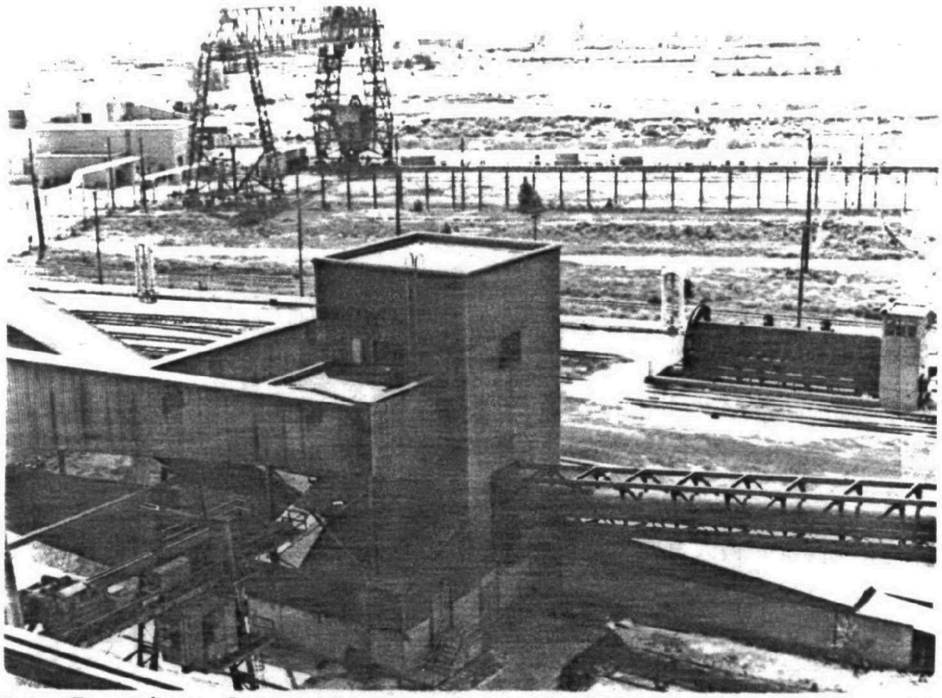


Photo No. 7 View from the roof of Boiler 5 facing southeast. The coal junction house is shown in the center of the photo. The gantry crane is shown in the upper left hand corner. The coal car dumper is shown in the right center of the photograph.

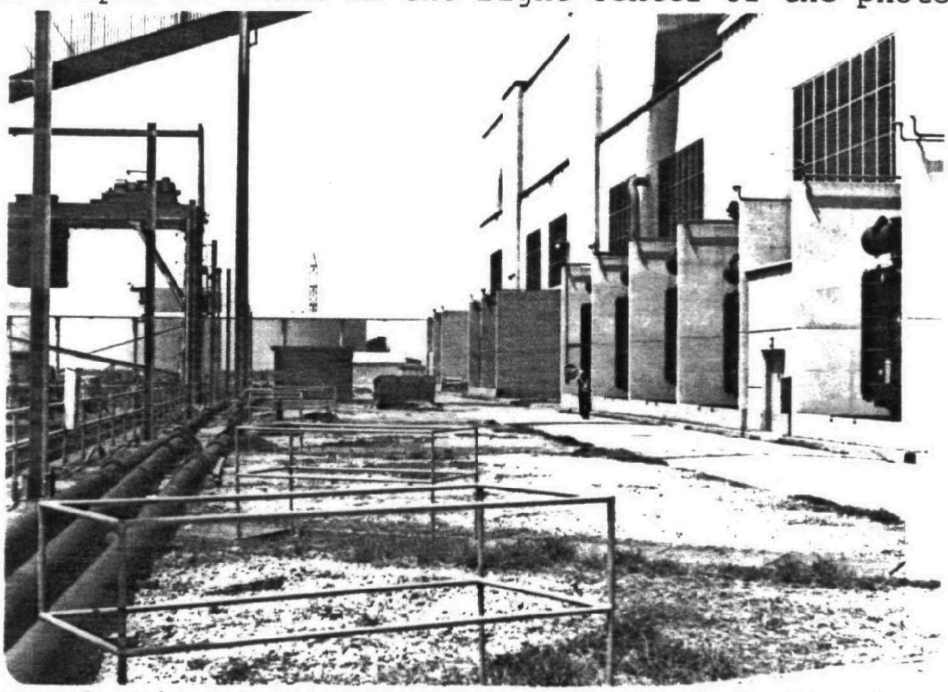


Photo No. 8 View from ground level near the Boiler 1 area looking northwest. Some of the plant's 4 kV transformers are shown in the right center of the photograph.

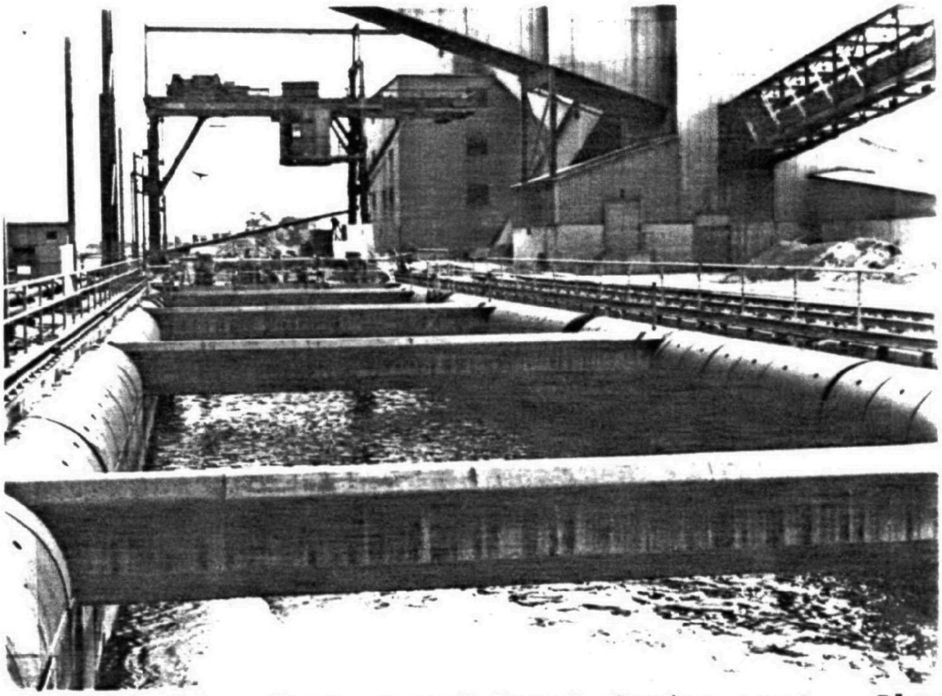


Photo No. 9 View from ground level facing east. Slag tanks for Boilers 5 and 6 are shown in the foreground. The coal junction house (upper right corner) is partially blocking the breaker house shown in the upper center of the photo.

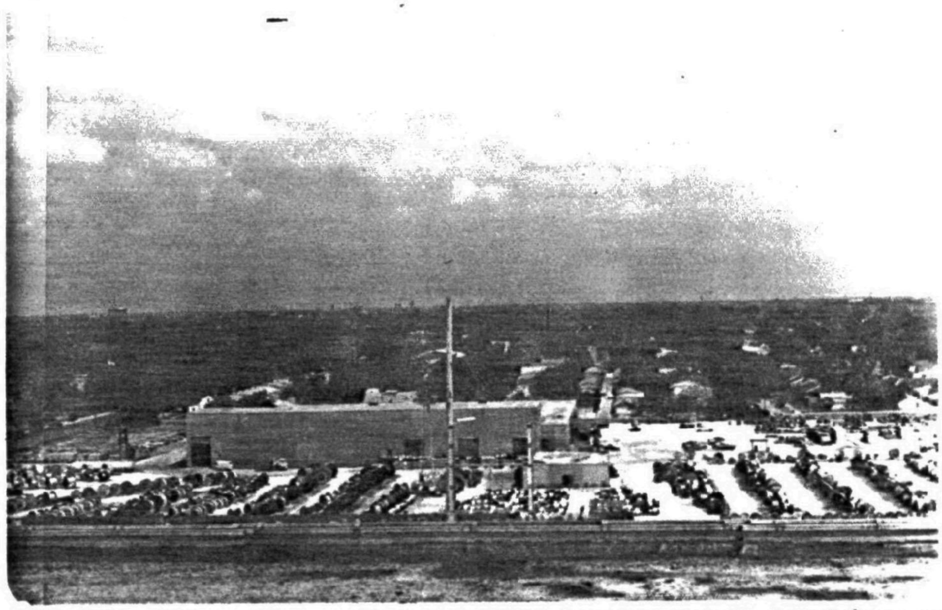


Photo No. 10 View from the boiler house roof looking north. The warehouse is shown in the bottom center of the photo. A portion of the wooded residential area is shown across the photograph, just below center.

TABLE P-1. ESTIMATED CAPITAL COST OF A SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILERS 1 THROUGH 6 AT THE RIDGELAND POWER PLANT (1978)

Direct Costs			
A.	Soda Ash Preparation		
	Storage silos		$ 191,000
	Vibrating feeders		6,000
	Storage tanks		57,000
	Agitators		26,000
	Pumps and motors		2,000
		Total A =	$ 272,000
B.	SO_2 Scrubbing		
	Absorbers		$ 17,718,000
	Fans and motors		1,960,000
	Pumps and motors		518,000
	Reheaters		3,096,000
	Soot blowers		1,956,000
	Ducting		7,211,000
	Valves		824,000
		Total B =	$ 33,283,000
C.	Purge Treatment		
	Refrigeration unit		$ 504,000
	Heat exchangers		76,000
	Tanks		104,000
	Dryer		48,000
	Elevator		15,000
	Pumps and motors		827,000
	Centrifuge		1,008,000
	Crystallizer		1,210,000
	Storage silo		191,000
	Feeder		6,000
		Total C =	$ 3,989,000

(continued)

TABLE P-1 (continued)

D.	Regeneration		
	Pumps and motors		$ 603,000
	Evaporators and reboilers		12,525,000
	Heat exchangers		1,652,000
	Tanks		138,000
	Stripper		235,000
	Blower		537,000
		Total D =	$ 15,690,000
E.	Particulate Removal		
	Venturi scrubber		$ 7,779,000
	Tanks		212,000
	Pumps and motors		571,000
		Total E =	$ 8,562,000
	Total direct costs = A + B + C + D + E = F =		$ 61,796,000
Indirect Costs			
	Interest during construction		$ 6,180,000
	Field labor and expenses		6,180,000
	Contractor's fee and expenses		3,090,000
	Engineering		6,180,000
	Freight		772,000
	Offsite		1,854,000
	Taxes		000
	Spares		309,000
	Allowance for shakedown		3,090,000
	Acid plant		3,659,000
		Total indirect costs G =	$ 31,314,000
		Contingency H =	18,622,000
		Total = F + G + H =	$111,732,000
		Coal conversion costs	17,795,000
		Grand total	$129,527,000
		$/kW	215.52

TABLE P-2. ESTIMATED ANNUAL OPERATING COSTS OF A SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILERS 1 THROUGH 6 AT THE RIDGELAND POWER PLANT (1978)

	Quantity	Unit Cost	Annual Cost
Raw Materials			
Soda ash	2.01 tons/h	\$77.02/ton	\$ 636,000
Utilities			
Process water	8375 gal/min	\$0.66/10^3 gal	1,358,000
Cooling water	35.5 x 10^3 gal/min	\$0.01/10^3 gal	89,000
Electricity	19,004 kW	33.1 mills/kWh	2,568,000
Reheat steam	117.6 x 10^6 Btu/h	\$1.685/10^6 Btu	810,000
Process steam	560.6 x 10^6 Btu/h	\$1.685/10^6 Btu	3,861,000
Operation Labor			
Direct labor	3 men/day	\$9.55/man-hour	250,000
Supervision	15% of direct labor		38,000
Maintenance			
Labor and materials	4% of fixed investment		4,469,000
Supplies	15% of labor and materials		670,000
Overhead			
Plant	50% of operating and maintenance		2,714,000
Payroll	20% of operating labor		58,000
Fixed Costs			
Depreciation	(7.69%)		
Interim replacement	(0.35%)		
Insurance	(0.30%)		
Taxes	(4.00%), Σ = 23.54% of fixed investment		
Capital cost	(11.20%)		
Total fixed costs			26,302,000
Total cost			\$ 43,823,000
Credits (byproducts)			
Sulfuric acid	27.9 tons/h	\$51.90/ton	(5,916,000)
Na_2SO_4	2.01 tons/h	\$42.65/ton	(352,000)
Total byproduct credits			\$ (6,268,000)
Fuel credit			(18,516,000)
Net annual cost			\$ 19,039,000
Mills/kWh			7.73

Table P-3. RETROFIT EQUIPMENT DIMENSIONS REQUIRED FOR THE SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILERS 1, 2, 3, 4, 5, AND 6 AT THE RIDGELAND POWER PLANT

Module Description	Number Required	Size/Capacity
Absorber	4 1 1	80 MW unit 139 MW unit 144 MW unit
Flue gas fans	6	Scaled to train size
Na_2CO_3 storage	1	1450 tons (30-day storage)
Na_2CO_3 preparation	1	4020 lb/hr, Na_2CO_3
SO_2 regeneration	1	36,500 lb/hr, SO_2
Purge treatment	1	4020 lb/hr, Na_2SO_4
Sulfuric acid plant	1	305 ton/day, H_2SO_4

Table P-4. RETROFIT EQUIPMENT DIMENSIONS REQUIRED FOR THE SODIUM SOLUTION REGENERABLE SYSTEM FOR BOILERS 1, 2, 3, 4, 5, AND 6 AT THE RIDGELAND POWER PLANT

Item	Number Required	Dimensions, ft
Na_2CO_3 storage		30 diam x 60 high
Absorber feed surge tank	1	44 diam x 55 high
Turbulent contact absorbers	4 2	45 high x 15 wide x 37 long 45 high x 15 wide x 56 long
Regeneration plant	1	100 x 250
Purge treatment plant	1	90 x 220
Acid plant	1	105 x 220

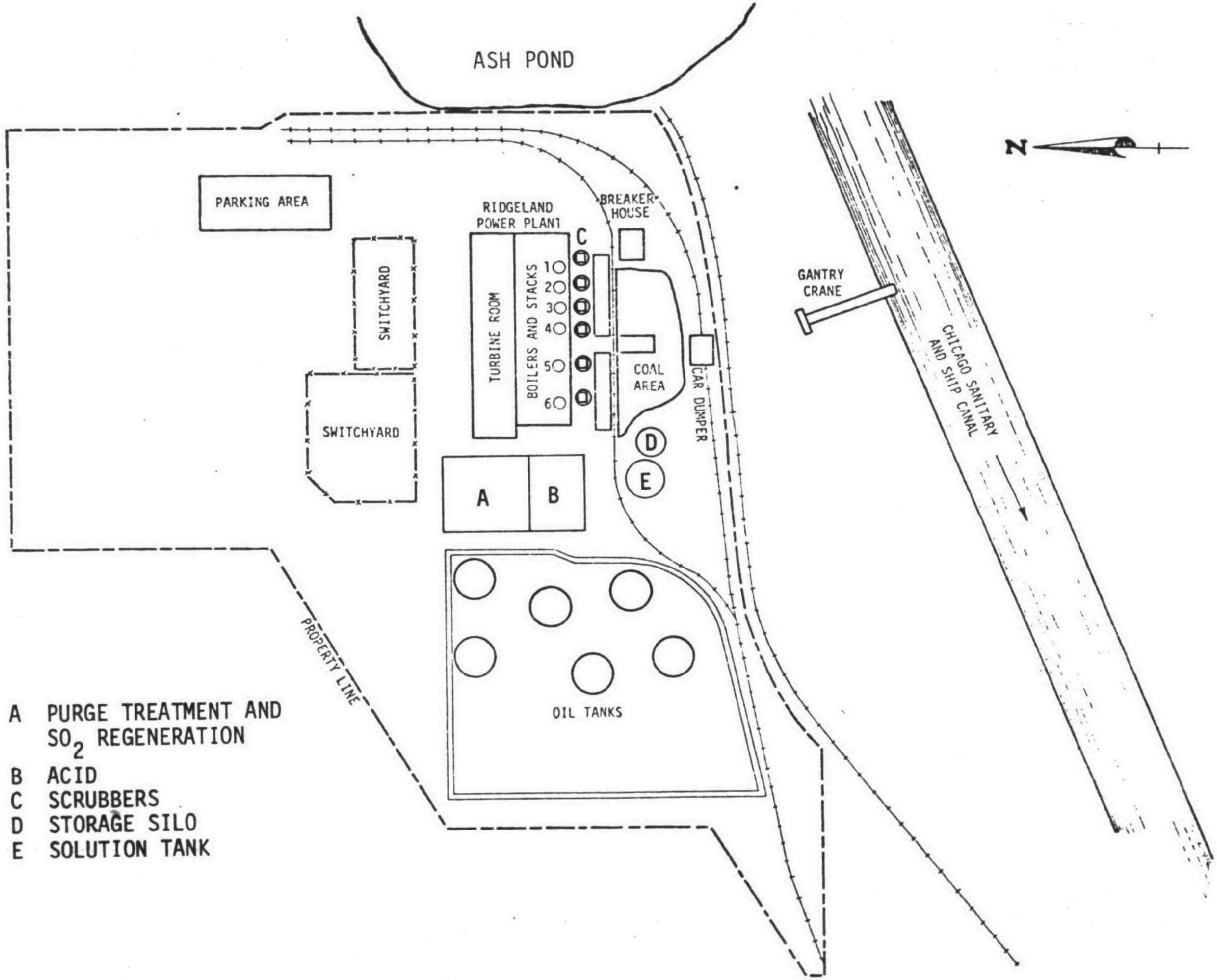


Figure P-1. Site plan showing possible location of major components for the sodium solution regenerable system for Boilers 1,2,3,4,5, and 6 at the Ridgeland power plant.

TABLE P-5. ESTIMATED CAPITAL COST OF A LIMESTONE SCRUBBING SYSTEM FOR BOILERS 1 THROUGH 6 AT THE RIDGELAND POWER PLANT (1978)

Direct Cost			
A.	Limestone Preparation		
	Conveyors		$ 586,000
	Storage silo		175,000
	Ball mills		971,000
	Pumps and motors		379,000
	Storage tanks		531,000
		Total A =	$ 2,642,000
B.	Scrubbing		
	Absorbers		$14,261,000
	Fans and motors		2,176,000
	Pumps and motors		1,148,000
	Tanks		894,000
	Reheaters		3,096,000
	Soot blowers		978,000
	Ducting and valves		8,035,000
		Total B =	$30,588,000
C.	Sludge Disposal		
	Clarifiers		$ 423,000
	Vacuum filters		619,000
	Tanks and mixers		14,000
	Fixation chemical storage		58,000
	Pumps and motors		137,000
	Sludge pond		1,618,000
	Mobile equipment		64,000
		Total C =	$ 2,933,000

(continued)

TABLE P-5 (continued)

D.	Particulate Removal	
	Venturi scrubber	$ 7,778,000
	Tanks	243,000
	Pumps and motors	333,000
	Total D =	$ 8,354,000
	Total direct costs = A + B + C + D = E =	$ 44,517,000
Indirect Costs		
	Interest during construction	$ 4,452,000
	Field overhead	4,452,000
	Contractor's fee and expenses	2,226,000
	Engineering	4,452,000
	Freight	556,000
	Offsite	1,336,000
	Taxes	000
	Spares	223,000
	Allowance for shakedown	2,226,000
	Total indirect costs F =	$ 19,923,000
	Contingency G =	12,888,000
	Total = E + F + G =	$ 77,328,000
	Coal conversion costs	17,795,000
	Grand total	$ 95,123,000
	$/kW	158.27

TABLE P-6. ESTIMATED ANNUAL OPERATING COSTS OF A LIMESTONE SCRUBBING SYSTEM FOR BOILERS 1 THROUGH 6 AT THE RIDGELAND POWER PLANT (1978)

	Quantity	Unit Cost	Annual Cost
Raw Materials			
Limestone	38.9 tons/h	$13.06/ton	$ 2,079,000
Fixation chemicals	100 tons/h	$2.20/ton	903,000
Utilities			
Water	250 gal/min	$0.66/10^3 gal	41,000
Electricity	14,205 kW	33 mills/kWh	1,920,000
Fuel for reheat	117.6 x 10^6 Btu/h	$1.685/10^6 Btu	810,000
Operating Labor			
Direct labor	3 men/day	$9.55/man-hour	251,000
Supervision	15% of direct labor		38,000
Maintenance			
Labor and materials	4% of fixed investment		3,093,000
Supplies	15% of labor and material		464,000
Overhead			
Plant	50% of operation and maintenance		1,923,000
Payroll	20% of operating labor		58,000
Trucking			
Bottom/fly ash and sludge removal			6,766,000
Fixed Costs			
Depreciation	(7.69%)		
Interim replacement	(0.35%), Σ = 23.54% of fixed investment		
Insurance	(0.30%)		
Taxes	(4.00%)		
Capital costs	(11.20%)		
Total fixed costs			18,203,000
Total costs			$ 36,549,000
Fuel credit			(18,516,000)
Net annual cost			$ 18,033,000
Mills/kWh			7.32

Table P-7. RETROFIT EQUIPMENT AND FACILITIES REQUIRED FOR THE LIMESTONE SCRUBBING SYSTEM FOR BOILERS 1, 2, 3, 4, 5, AND 6 AT THE RIDGELAND POWER PLANT

Module Description	Number Required	Size/Capacity
Limestone storage	1	28,000 tons (30-day storage)
Limestone slurry	1	38.9 ton/hr limestone
Turbulent contact	4	80 MW unit
absorbers	1	139 MW unit
	1	144 MW unit

Table P-8. RETROFIT EQUIPMENT DIMENSIONS REQUIRED FOR THE LIMESTONE SCRUBBING SYSTEM FOR BOILER 1, 2, 3, 4, 5, AND 6 AT THE RIDGELAND POWER PLANT

Item	Number Required	Dimensions, ft
Limestone storage pile	1	115 wide x 325 long
Limestone silos	3	23 diam x 50 high
Limestone slurry tanks	1	95 diam x 20 high
Ball mill building	1	40 x 40
Turbulent contact	4	45 high x 15 wide x 30 long
absorbers	2	45 high x 15 wide x 45 long
Clarifiers	2	165 diam x 20 high
Vacuum filter building	1	40 x 40

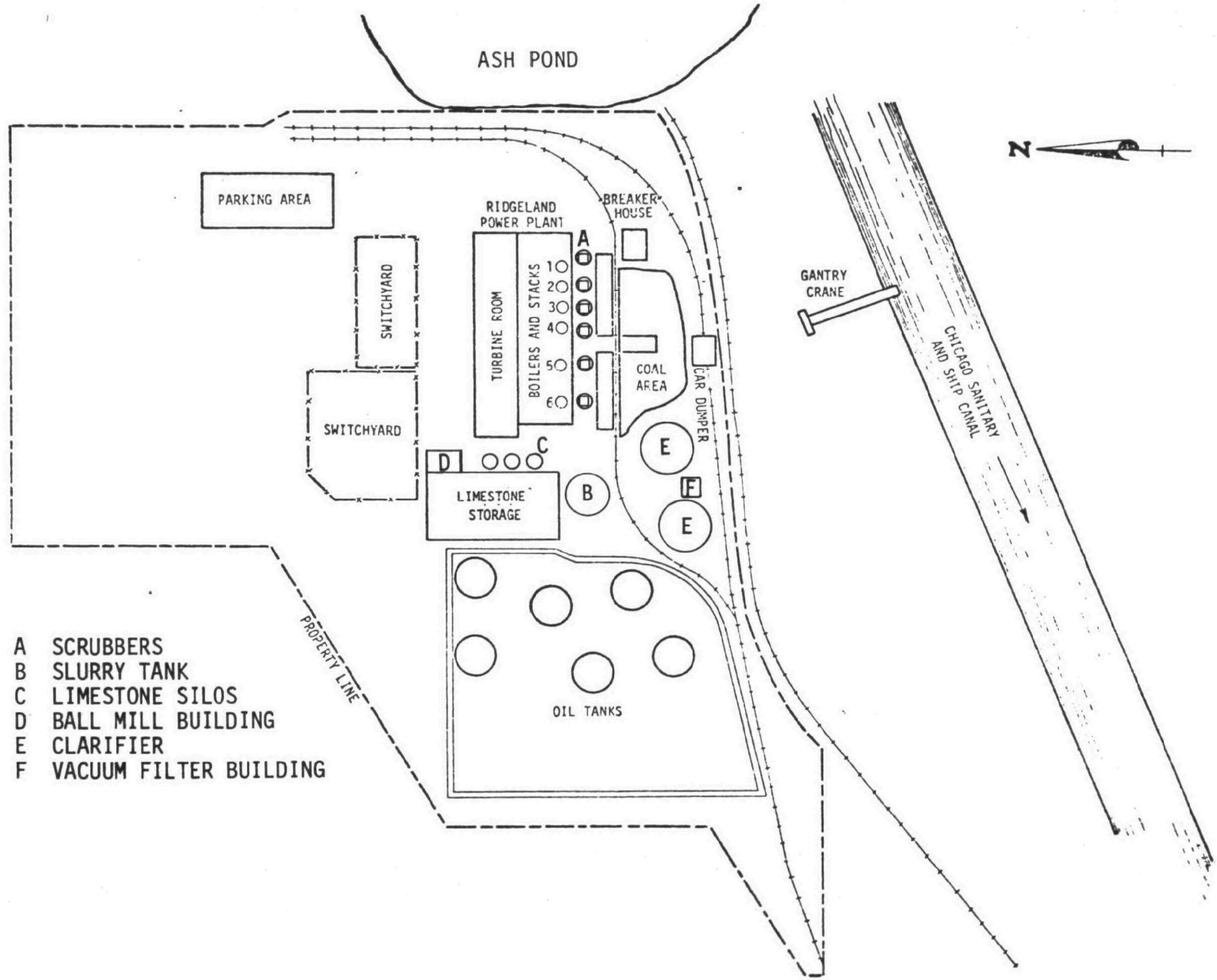


Figure P-2. Site plan showing possible location of major components for the limestone system for Boilers 1,2,3,4,5, and 6 at the Ridgeland power plant.

TABLE P-9. ESTIMATED CAPITAL COST OF ELECTROSTATIC PRECIPITATORS FOR BOILERS 1 THROUGH 6 AT THE RIDGELAND POWER PLANT (1978)

Direct Costs		
ESP		$ 10,518,000
Ash handling		1,701,000
Ducting		1,660,000
	Total direct costs	$ 13,879,000
Indirect Costs		
Interest during construction	8% of direct costs	$ 1,110,000
Contractor's fee	10% of direct costs	1,388,000
Engineering	6% of direct costs	833,000
Freight	1.25% of direct costs	173,000
Offsite	3% of direct costs	416,000
Taxes	0% of direct costs	000
Spares	1% of direct costs	139,000
Allowance for shakedown	3% of direct costs	416,000
Total indirect costs		$ 4,475,000
Contingency		3,671,000
Total		$ 22,025,000
Coal conversion costs		17,795,000
Grand total		$ 39,820,000
$/kW		66.26

TABLE P-10. ESTIMATED ANNUAL OPERATING COSTS OF ELECTROSTATIC PRECIPITATOR FOR BOILERS 1 THROUGH 6 AT THE RIDGELAND POWER PLANT (1978)

Utilities	Quantity	Unit Cost	Annual Costs
Electricity	2016 kW	33.1 mills/kWh	$ 274,000
Water	1705 x 10^3 gal/yr	$0.01/$10^3$ gal	1,000
Operating Labor			
Direct labor	0.5 man/shift	$9.55/man-hour	250,000
Supervision	15% of direct labor		38,000
Maintenance			
Labor and materials	2% of fixed investment		441,000
Supplies	15% of labor and materials		66,000
Overhead			
Plant	50% of operating and maintenance		398,000
Payroll	20% of operating labor		58,000
Trucking			
Bottom/fly ash removal			1,774,000
Fixed costs			
Depreciation	(7.69%)		
Interim replacement	(0.35%), Σ = 23.54% of fixed investment		
Insurance	(0.30%)		
Taxes	(4.00%)		
Capital cost	(11.20%)		
Total fixed cost			5,185,000
Total cost			$ 8,485,000
Fuel credit			(32,240,000)
Net annual credit			$(23,755,000)
Mills/kWh			(9.64)

Table P-11. ELECTROSTATIC PRECIPITATOR DESIGN VALUES

FOR BOILERS 1,2,3,4,5, AND 6 AT THE RIDGELAND POWER PLANT

Design Parameter	Value					
	1	2	3	4	5	6
Collection efficiency, % (Overall)	86.4	86.4	86.4	86.4	86.4	86.4
Specific collecting area, ft^2/1000 acfm	256	256	256	256	256	256
Total collecting area, ft^2	98,220	98,220	98,220	98,220	139,660	139,660
Superficial velocity, fps	4	4	4	4	4	4
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	18x89x24	18x89x24	18x89x24	18x89x24	18x126x24	18x126x24

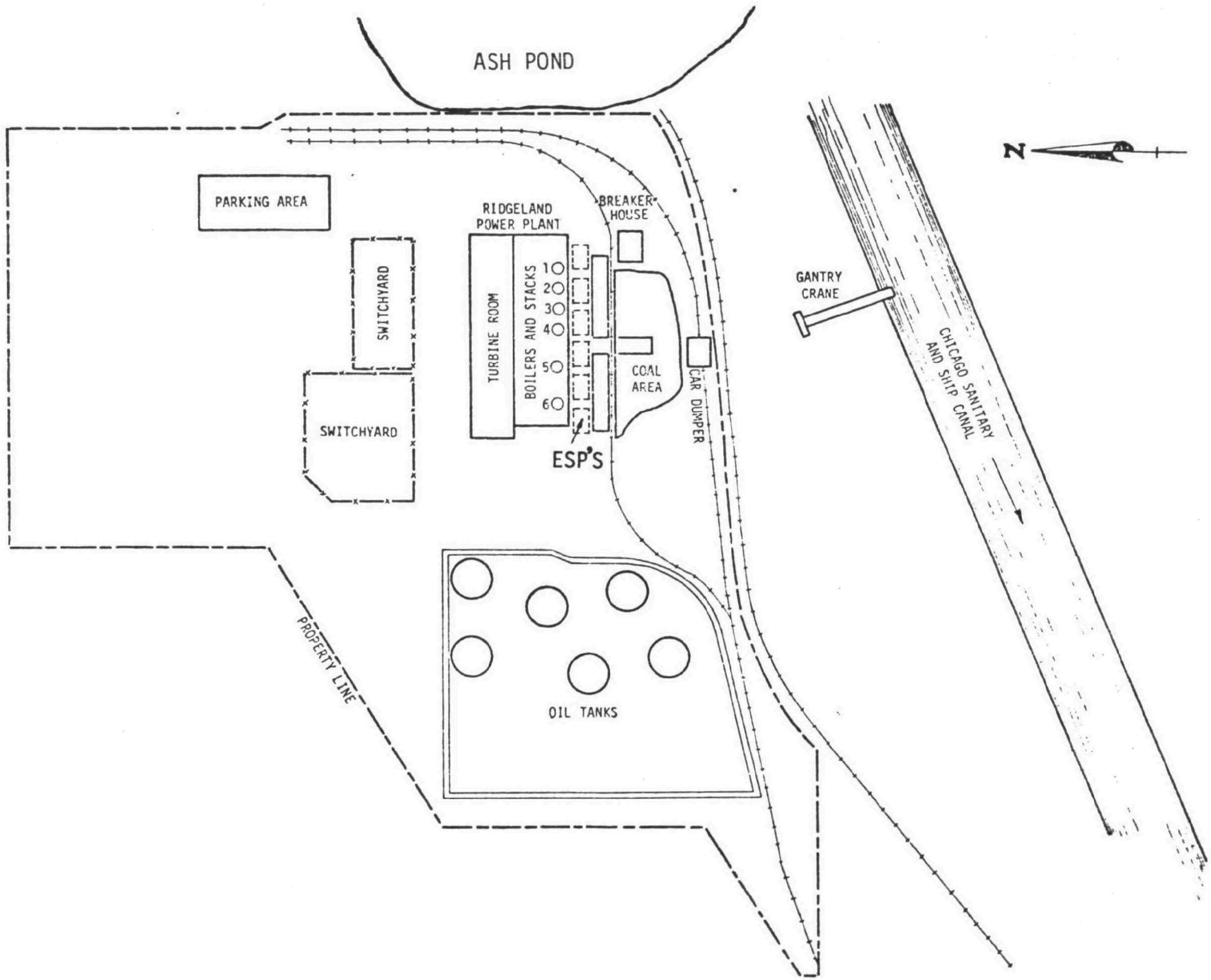


Figure P-3. Site plan showing possible locations of new ESP's for Boilers 1, 2, 3, 4, 5, and 6 at the Ridgeland power plant.

APPENDIX Q

RIVERTON POWER PLANT

CONTENTS

FIGURES

TABLES

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Potomac Edison Company
   Allegheny Power Service Corp.
2. MAIN OFFICE: 800 Cabin Hill Drive Greensburg, PA 15601
3. RESPONSIBLE OFFICER: C. G. McVay
4. POSITION: V.P. System Power Supply
5. PLANT NAME: Riverton
6. PLANT LOCATION: Front Royal, P.O. Box 243, Warren County, Virginia 22630
7. RESPONSIBLE OFFICER AT PLANT LOCATION: John Coulter
8. POSITION: Plant Superintendent
9. POWER POOL - ECAR

DATE INFORMATION GATHERED: April 22,1976

PARTICIPANTS IN MEETING:

Robert L. Ballentine - Allegheny Power Service Corporation
John W. Coulter - Station Superintendant
Bernie Turlinski - U.S. Environmental Protection Agency
D. J. Gaston - Virginia Air Pollution Control Board
Wayne E. Peters - Federal Energy Administration
N. David Noe - PEDCo Environmental, Inc.
David M. Augenstein - PEDCo Environmental, Inc.

B. ATMOSPHERIC EMISSIONS	Boiler number 1				
1. PARTICULATE EMISSIONS[a] uncontrolled					
LB/MM BTU Full load	0.06 (oil) 0.19 (coal)				
GRAINS/ACF	NA				
LB/HR (FULL LOAD)	38 (oil)				
TONS/YEAR ( )	3.15 (c)				
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION	1				
REGULATION & SECTION NO.	Part IV rule Ex -3 4.30 (a) 11				
LB/MM BTU	0.1899				
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.	Same				
LB/MM BTU					
3. SO_2 EMISSIONS[a]					
LB/MM BTU	0.253 (oil) 2.64 (coal)				
LB/HR (FULL LOAD)	158 (c)				
TONS/YEAR ( )	13 (c)				
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.	Part IV Rule Ex -5 4.51 (a) 1				
LB/MM BTU	2.64				
~~lb/hr (S = 2.64K)~~	1782 lb/hr				
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.	Same				
LB/MM BTU					

a) Identify whether results are from stack tests or estimates

C. SITE DATA

1. U.T.M. COORDINATES Lat. 38° 57' 50" : Long. 78° 10' 40"

2. ELEVATION ABOVE MEAN SEA LEVEL (FT) App 530

3. SOIL DATA: BEARING VALUE ______

   PILING NECESSARY ______

4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR) REVD

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA

5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE)

6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): App NA 630

D. BOILER DATA

	Boiler number				
	1				
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK	Peak				
2. TOTAL HOURS OPERATION (19 75)	504				
3. AVERAGE CAPACITY FACTOR (19 75)	2.2%				
4. SERVED BY STACK NO.	1				
5. BOILER MANUFACTURER	Riley				
6. YEAR BOILER PLACED IN SERVICE	1949				
7. REMAINING LIFE OF UNIT					
8. GENERATING CAPACITY (MW)					
RATED	40				
MAXIMUM CONTINUOUS	40				
PEAK					
9. FUEL CONSUMPTION:					
OIL RATED	114 Bar/Hr.				
(GPH) MAXIMUM CONTINUOUS					
PEAK					
10. ACTUAL FUEL CONSUMPTION					
COAL (TPY) (19 75)	0				
OIL (GPY) (19 75)	787,576				
11. WET OR DRY BOTTOM	Dry				
12. FLY ASH REINJECTION (YES OR NO)	No				
13. STACK HGT ABOVE GRADE (FT.)	130				
14. I.D. OF STACK AT TOP (INCHES)	108				

Notes:

	Boiler number				
	1				
15. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS					
MANUFACTURER	UOP				
TYPE	MCAX				
EFFICIENCY: DESIGN/ACTUAL (%)	85/79				
MASS EMISSION RATE: (GR/ACF)					
(#/HR)	38 (oil)				
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER	None				
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)					
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)					
16. EXCESS AIR: DESIGN/ACTUAL (%)	20				

Notes:

	Boiler number				
	1				
17. FLUE GAS RATE (ACFM)					
@ 100% LOAD	212,000				
@ 75% LOAD	180,000				
@ 50% LOAD	120,000				
18. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	360				
@ 75% LOAD	340				
@ 50% LOAD	300				
19. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	56				
@ 75% LOAD	46				
@ 50% LOAD	36				
20. FLY ASH: TOTAL COLLECTED (TONS/YEAR) 1973	2,204				
DISPOSAL METHOD	Land fill				
DISPOSAL COST ($/~~TON~~)	$ 400.				
21. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR) 1973	1,087				
DISPOSAL METHOD	Land fill				
DISPOSAL COST (~~$/TON~~)	$1,400				
22. EXHAUST DUCT DIMENSIONS @ STACK					
23. ELEVATION OF TIE IN POINT TO STACK					
24. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE) One week	4/18/77 5/8/78				

a) Identify source of values (test or estimate)

Notes:

E. I.D. FAN DATA	Boiler number				
1. MAXIMUM STATIC HEAD (IN. W.C.)					
2. WORKING STATIC HEAD (IN. W.C.)					

Notes:

F. FLY ASH DISPOSAL AREAS Deteriorated 15 acre pond

1. AREAS AVAILABLE (ACRES) 20-30 Acres
2. YEARS STORAGE (ASH ONLY) Pond not in use
3. DISTANCE FROM STACK (FT.) 800
4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT Pond not in use

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION
   a.
   b.
   c.
   d.
2. QUANTITY USED BY SEAM AND/OR MINE
   a.
   b.
   c.
   d.
3. ANALYSIS
   GHV (BTU/LB) 11,624
   S (%) 3.2
   ASH (%) 21.4
   MOISTURE (%) 2.6
4. PPT PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA

1. TYPE No. 2
2. S CONTENT (%) 0.20
3. ASH CONTENT (%) 0.005
4. SPECIFIC GRAVITY
5. GHV (BTU/GAL) 138,695

I. COST DATA

ELECTRICITY X

WATER N/A

STEAM N/A

J. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE? Transformer required? ~~440~~ KW ~~breaker~~

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE? 230 V 440V

K. OIL/GAS TO COAL CONVERSION DATA

1. HAS THE BOILER EVER BURNED COAL?

Boiler No.	1				
Yes or No.	Yes				

2. SYSTEM AVAILABILITY

2.1 COAL HANDLING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☒ ☐

c. Of the following items which do not need to be replaced: Maintenance

		Yes	No	
Unloading equipment	parts	☒	☐	
Stack Reclaimer	belts	☐	☒	
Bunkers	9 month - lead time	☒	☐	
Conveyors		☐	☒	No. 2
Scales		☒	☐	
Coal Storage Area	Maintenance	☒	☐	

2.2 FUEL FIRING — Need a Bulldozer

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☐ x ☒ partially

c. Of the following items which do not need to be replaced:

		Yes	No
Pulverizers or Crushers	Rebuilding	☒	☐
Feed Ducts		☒	☐
Fans		☒	☐
Controls		☒	☐

2.3 GAS CLEANING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☐ ☐

c. Of the following items which do not need to be replaced:

		Yes	No
Electrostatic Precipitator	N/A	☐	☐
Cyclones		☒	☐
Fly Ash Handling Equipment		☒	☐
Soot Blowers - Air Compressors		☒	☐
Wall deslaggers		☒	☐

2.4 ASH HANDLING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☒ ☐

c. Of the following items which need to be replaced:

	Yes	No
Bottom Ash Handling	☐	☐
Ash Pond Maintenance	☐	☐

L. SUPPLEMENTARY CONTROL SYSTEM DATA

1. DOES THE PLANT NOW HAVE A SUPPLEMENTAL CONTROL SYSTEM (SCS)? Yes [ ] No [X]

   If yes, attach a description of the system.

2. IS THE PLANT CAPABLE OF SWITCHING TO LOW SULFUR FUELS? Yes [X] No [ ]

   2.1 Storage capacity for low sulfur fuels (tons, bbls, days)

   2.2 Bunkers available for low sulfur coal storage? Yes [X] No [ ]

   2.3 Handling facilities available for low sulfur fuels Yes [X] No [ ]

   If yes, describe ______________________

   ____

   2.4 Time required to switch fuels and fire the low sulfur fuel in the boiler (hrs)?______

3. IS THE PLANT CAPABLE OF LOAD SHEDDING?

   If yes, discuss ______________________

   ______________________ Yes [ ] No [ ]

4. IS THE PLANT CAPABLE OF LOAD SHIFTING?

   If yes, discuss ______________________

   ______________________ Yes [ ] No [ ]

5. POWER PLANT MONITORING SYSTEM

   5.1 Existing system Yes [ ] No [ ]

   a. Air quality instrumentation

	Number	Type
(1) Sulfur Oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulates		
- Intermittent	______	______
- Static	______	______
(3) Other (describe)__________		

   b. Meteorological instrumentation

   If yes, describe ______________________

   ____

   c. Is the monitoring data available? Yes [ ] No [ ]

   d. Is the monitoring data reduced and analyzed? Yes [ ] No [ ]

5.2 Proposed system Yes ☐ No ☐

If yes, describe ______________________

____

	Number	Type
a. Air monitoring instrumentation		
(1) Sulfur oxides - Continuous	____	____
- Intermittent	____	____
- Static	____	____
(2) Suspended particulate		
- Intermittent	____	____
- Static	____	____
(3) Other (describe) ____________		

b. Meteorological instrumentation

If yes, describe ______________

____

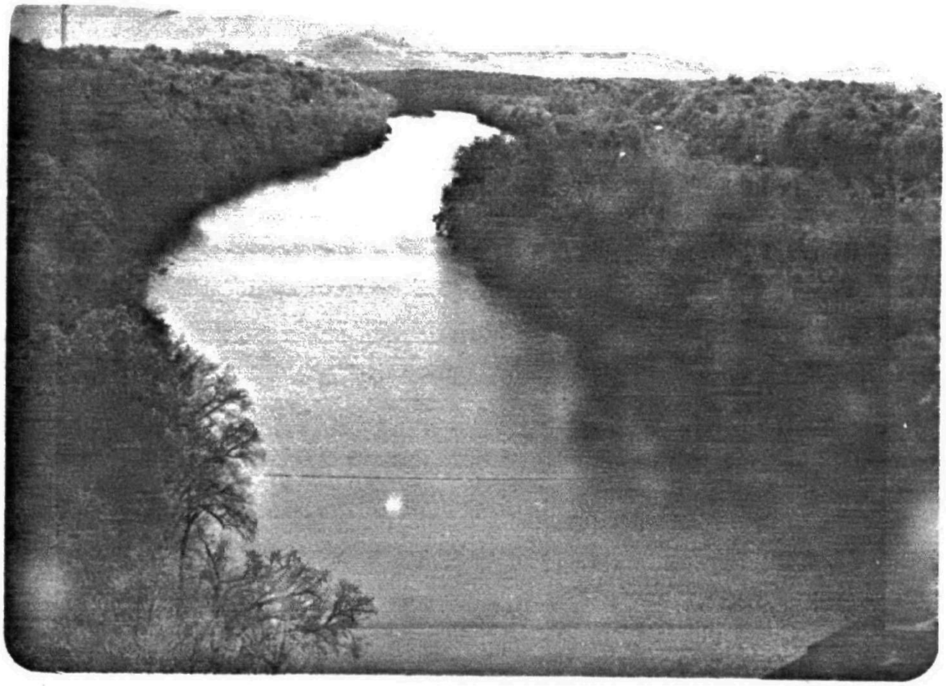


Photo No. 1. View from the boiler roof facing southeast showing the Shenandoah River and Blue Ridge Mountains.

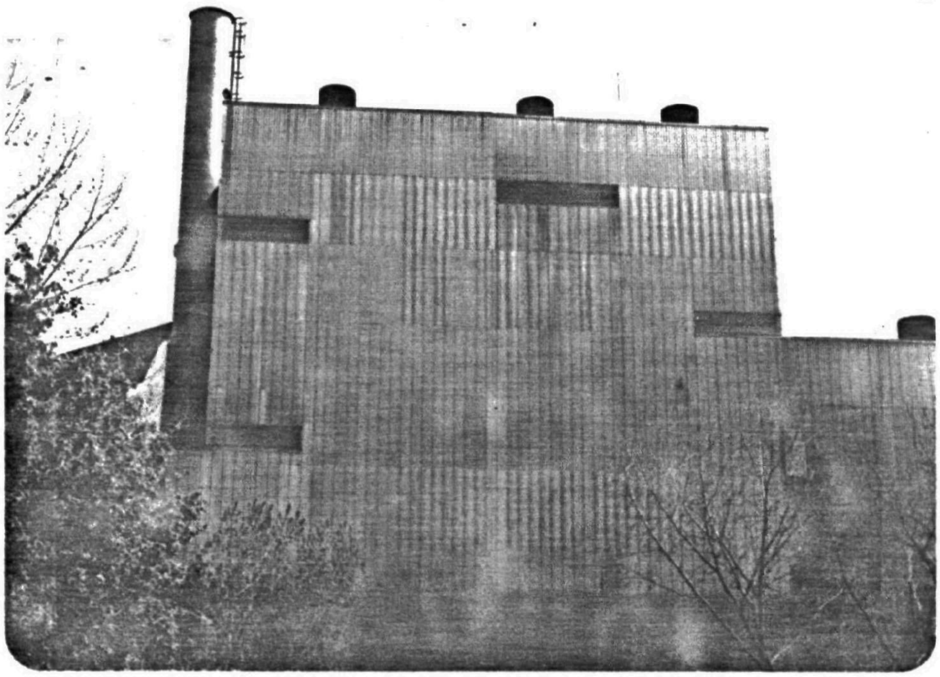


Photo No. 2. View from ground level facing east showing boiler stack and the west end of the plant.

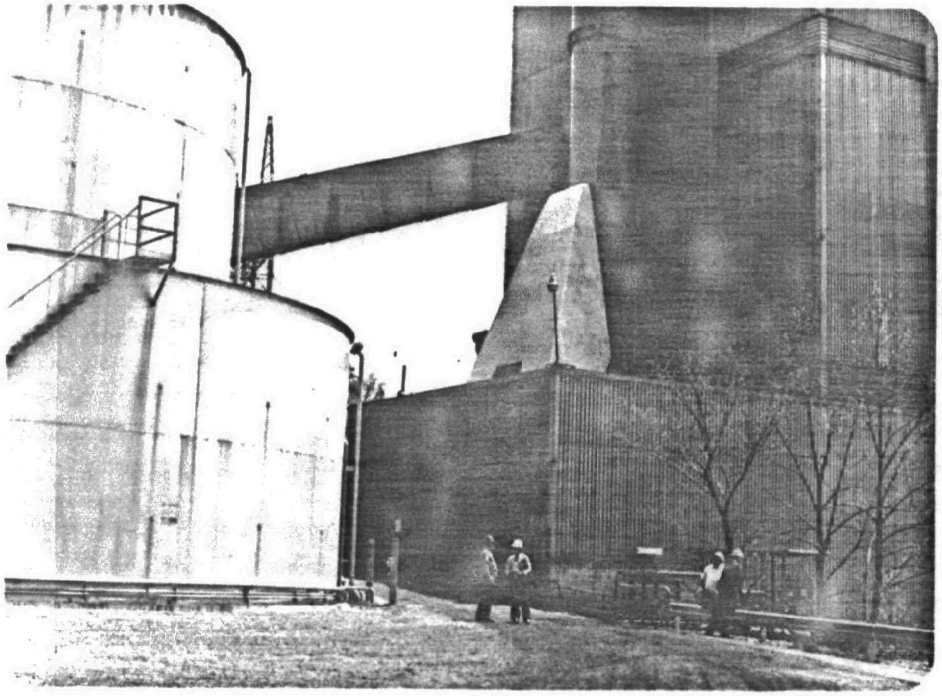


Photo No. 3. View from ground level facing southeast showing a portion of the oil storage facilities, boiler duct tie-in to the stack, and the coal conveyor.

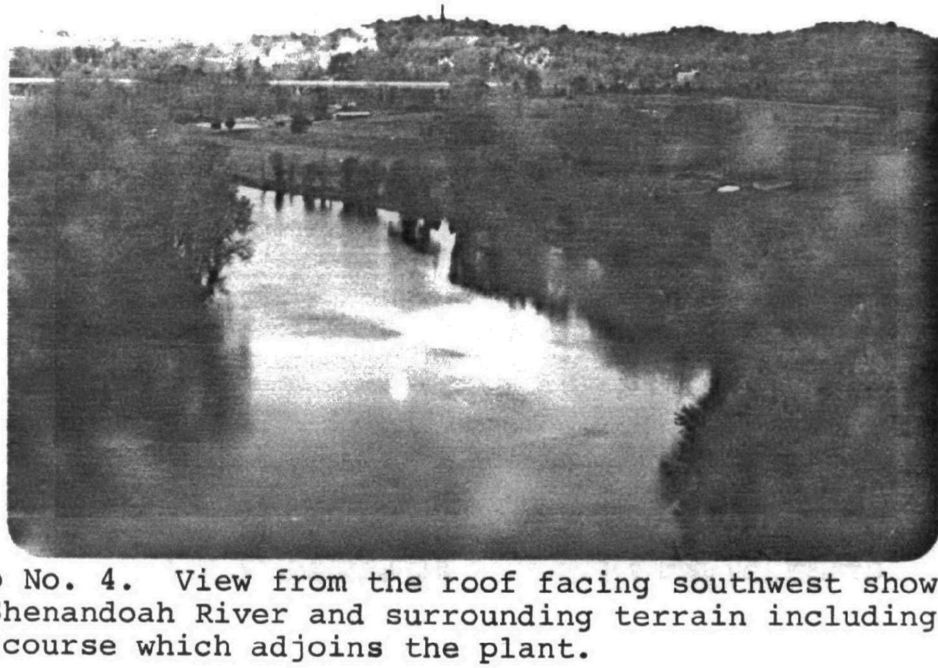


Photo No. 4. View from the roof facing southwest showing the Shenandoah River and surrounding terrain including the golf course which adjoins the plant.

Photo No. 5. View from the roof facing northwest showing the surrounding terrain.

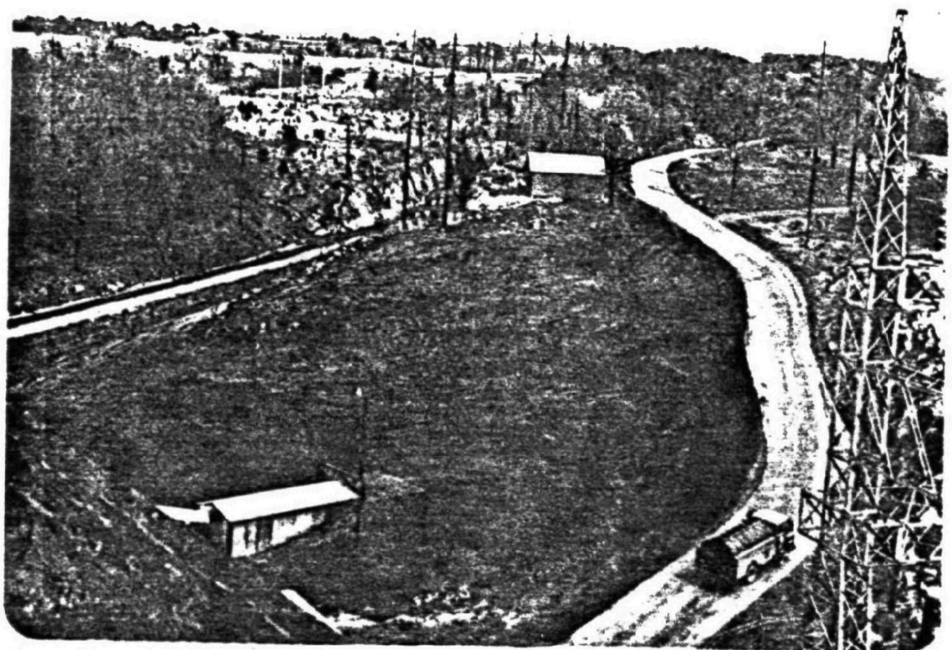


Photo No. 6. View from the roof facing north showing the coal storage area transfer station, and a portion of the electrical switchyard.

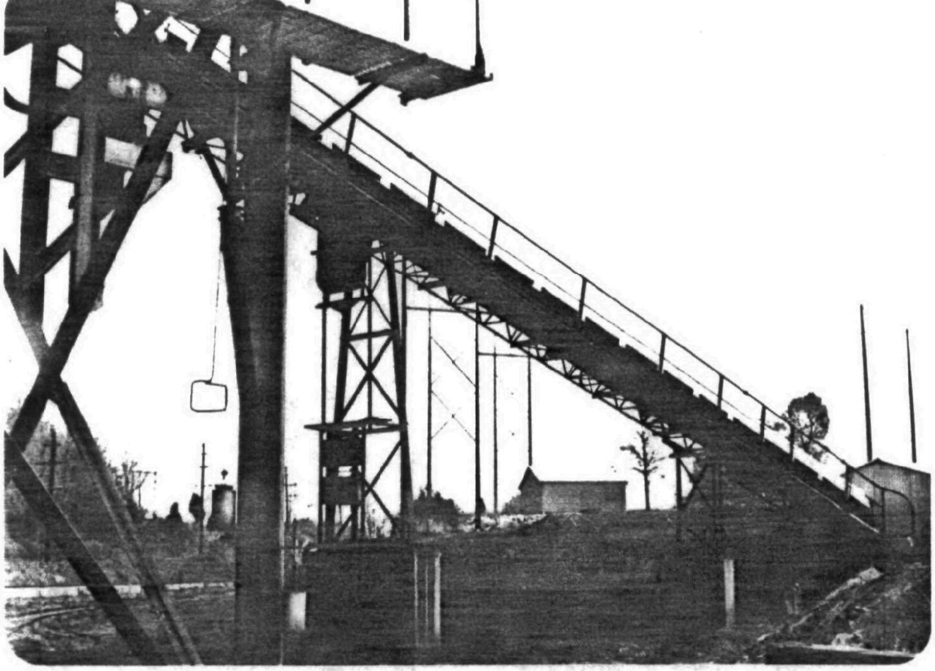


Photo No. 7. View from ground level facing north showing coal transfer house and conveyors. The coal storage area is in the background.

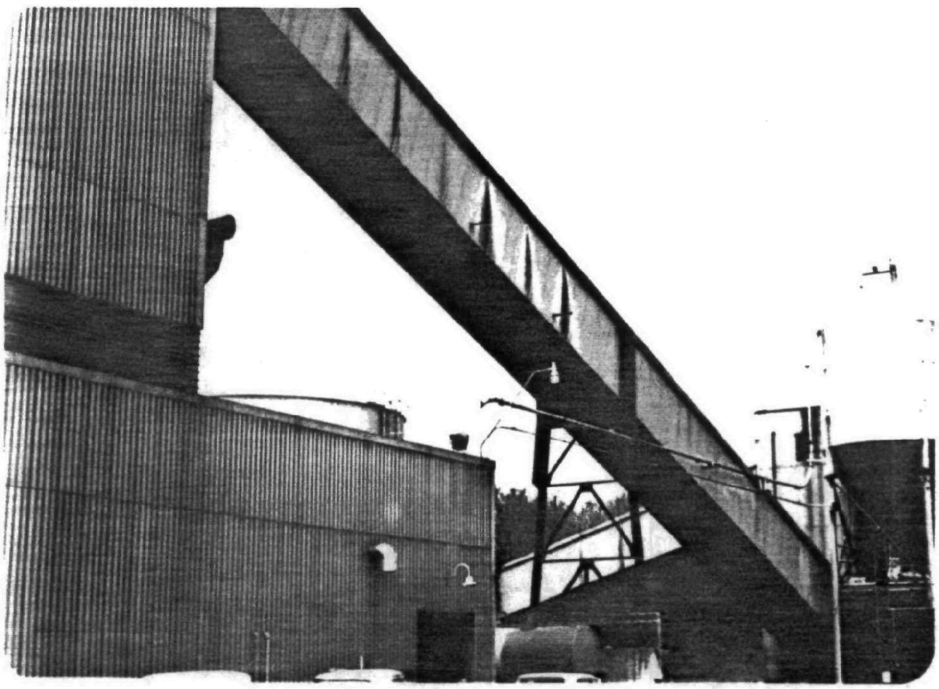


Photo No. 8. View from ground level facing northwest showing coal handling facilities located at the north end of the plant.

Photo No. 9. View from ground level facing southwest showing inactive ash settling basin located approximately 500 feet west of the plant. Plans are being initiated to pipe the plant effluent to this retired ash settling basin.

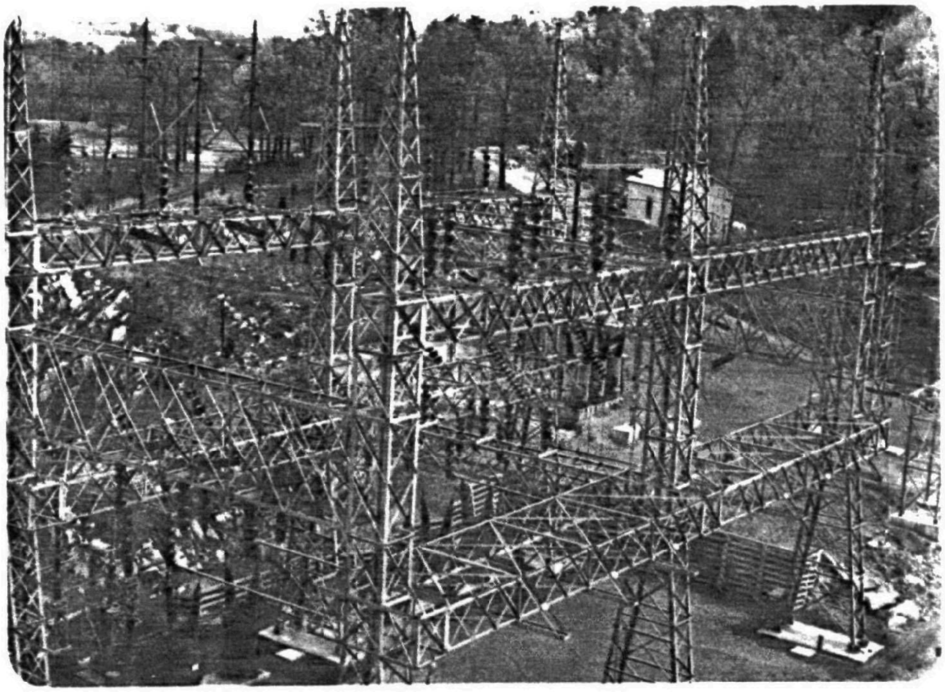


Photo No. 10. View from rooftop facing northeast showing electrical substation serving the plant.

TABLE Q-1. ESTIMATED CAPITAL COST OF AN ELECTROSTATIC PRECIPITATOR FOR BOILER 1 AT THE RIVERTON POWER PLANT (1978)

Direct Costs		
ESP		$ 1,514,000
Ash handling		220,000
Ducting		87,000
	Total direct costs	$ 1,821,000
Indirect Costs		
Interest during construction	8% of direct costs	$ 146,000
Contractor's fee	10% of direct costs	182,000
Engineering	6% of direct costs	109,000
Freight	1.25% of direct costs	23,000
Offsite	3% of direct costs	55,000
Taxes	0% of direct costs	000
Spares	1% of direct costs	18,000
Allowance for shakedown	3% of direct costs	55,000
Total indirect costs		$ 588,000
Contingency		482,000
Total		$ 2,891,000
Coal conversion costs		2,269,000
Grand total		$ 5,160,000
$/kW		129.00

TABLE Q-2. ESTIMATED ANNUAL OPERATING COSTS OF AN ELECTROSTATIC PRECIPITATOR FOR BOILER 1 AT THE RIVERTON POWER PLANT (1978)

Utilities	Quantity	Unit Cost	Annual Cost
Electricity	260 kW	27.55 mills/kWh	$ 11,000
Water	3003 10^3 gal/yr	$0.33/$10^3$ gal	1,000
Operating Labor			
Direct labor	1.5 men/shift	$8.50/man-hour	37,000
Supervision	15% of direct labor		6,000
Maintenance			
Labor and materials	2% of fixed investment		58,000
Supplies	15% of labor and materials		9,000
Overhead			
Plant	50% of operation and maintenance		55,000
Payroll	20% of operating labor		9,000
Trucking			
Bottom/fly ash removal			000
Fixed Costs			
Depreciation	(7.69%)		
Interim replacement	(0.35%), Σ = 19.54% of fixed investment		
Insurance	(0.30%)		
Taxes	(0.00%)		
Capital cost	(11.20%)		
Total fixed cost			$ 565,000
Total cost			$ 751,000
Fuel credit			(142,000)
Net annual cost			$ 609,000
Mills/kWh			64.37

Table Q-3. ELECTROSTATIC PRECIPITATOR DESIGN VALUES FOR BOILER 1 AT THE RIVERTON POWER PLANT

Design Parameter	Value
	1
Collection efficiency, % (Overall)	97.48
Specific collecting area, ft^2/1000 acfm	409
Total collecting area, ft^2	87,000
Superficial velocity, fps	4
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	30 x 29 x 39

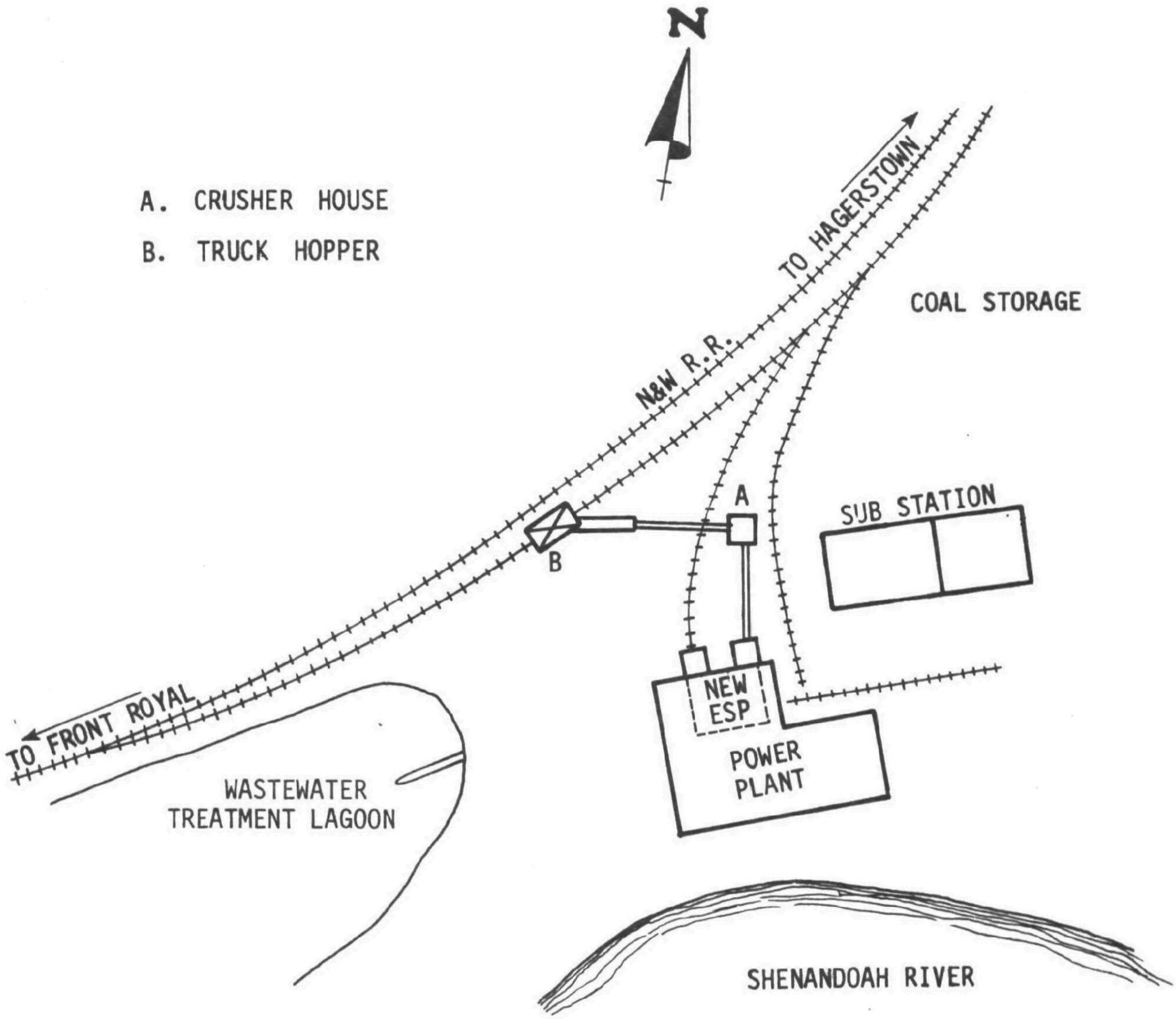


Figure Q-1. Site plan showing possible location of a new ESP for Boiler 1 at the Riverton power plant.

APPENDIX R

VIENNA POWER PLANT

CONTENTS

FIGURES

TABLES

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Delmarve Power & Light Co.
2. MAIN OFFICE: Wilmington, Deleware
3. RESPONSIBLE OFFICER: Hudson Hoen
4. POSITION: Director, Environmental Affairs
5. PLANT NAME: Vienna
6. PLANT LOCATION: Vienna, Maryland
7. RESPONSIBLE OFFICER AT PLANT LOCATION: David Windslow
8. POSITION: Superintendent
9. POWER POOL PJM

DATE INFORMATION GATHERED:

PARTICIPANTS IN MEETING:

Tom Evans - Delmarva Power & Light
Dick Parcels - Delmarva Power & Light
Bob Matthews - Delmarva Power & Light
D. Bruce McClenathan - Delmarva Power & Light
Clark I. Simms, Jr. - Delmarva Power & Light
Ralph Schumacher - Maryland Health Department
Bernie Turlinski - U.S. Environmental Protection Agency
N. David Noe - PEDCo Environmental, Inc.
Michael F. Szabo - PEDCo Environmental, Inc.
David M. Augenstein - PEDCo Environmental, Inc.

B. ATMOSPHERIC EMISSIONS	Boiler number				
	5	6	7	8	
1. PARTICULATE EMISSIONS[a]					
LB/MM BTU					
GRAINS/ACF					
LB/HR (FULL LOAD)	7	7	17	1140	
TONS/YEAR ( )					
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION	Area IV				
REGULATION & SECTION NO.	Reg. 10.03.41.03. B. (3). Stack-Stack basis				
LB/MM BTU	0.35	0.30	0.35	0.30	
OPACITY, PERCENT					
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a]					
LB/MM BTU					
LB/HR (FULL LOAD)					
TONS/YEAR ( )					
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.					
~~LB/MM BTU~~ Coal	1.0% Sulfur				
Residual Oil	0.5% Sulfur				
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					

) ıti wh ːr ılı re ɔm ck ːts e: at

C. SITE DATA

1. U.T.M. COORDINATES ____________________

2. ELEVATION ABOVE MEAN SEA LEVEL (FT) 8' above mean low water

3. SOIL DATA: BEARING VALUE ____________________

   PILING NECESSARY Yes

4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA

5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE)

6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): ____________

D. BOILER DATA

	Boiler number				
	5	6	7	8	
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK					
2. TOTAL HOURS OPERATION (1975)	3,165	6,447	2,490	4,848	
3. AVERAGE CAPACITY FACTOR (1975)	17.8	37.4	15.3	28.0	
4. SERVED BY STACK NO.	3&4	4&5	6	7	
5. BOILER MANUFACTURER	B&W	B&W	B&W	CE	
6. YEAR BOILER PLACED IN SERVICE	1947	1949	1951	1971	
7. REMAINING LIFE OF UNIT 28 yr. booklife	-	1	3	23	
8. GENERATING CAPACITY (MW)					
RATED	17	17	40	162	
MAXIMUM CONTINUOUS					
PEAK					
9. FUEL CONSUMPTION:					
~~COAL~~ OR OIL RATED					
BBl/h ~~(TPH) OR (GPH)~~ MAXIMUM CONTINUOUS	42	42	104	276	
PEAK					
10. ACTUAL FUEL CONSUMPTION					
COAL (TPY) (1971)	44,000	45,000	97,000	N.A.	
OIL ~~(GPY)~~ (1975) BBl/y	75,000	154,000	138,000	736,000	
11. HEAT RATE BTU/KWHR GAS					
COAL					
OIL					
12. WET OR DRY BOTTOM	dry	dry	dry	dry	
13. FLY ASH REINJECTION (YES OR NO)	No	No	No	Yes	
14. STACK HGT ABOVE GRADE (FT.)	133	133	133	160	
15. I.D. OF STACK AT TOP (INCHES)					

Notes:

	Boiler number				
	5	6	7	8	
16. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS					
MANUFACTURER	BUEL	UOP	UOP	UOP	
TYPE	MCTA	MCAX	MCAX	MCTA	
EFFICIENCY: DESIGN/ACTUAL (%)	85/60	85/0	85/0	87.5/87.5	
MASS EMISSION RATE: (GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER					
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)					
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)					
17. EXCESS AIR: DESIGN/ACTUAL (%)					

Notes:

	Stack number 3	4	5	6	7
18. FLUE GAS RATE (ACFM)					
@ 100% LOAD	52,000	104,000	52,000	242,000	672,000
@ 75% LOAD	40,700	81,000	40,700	185,900	504,000
@ 50% LOAD	28,000	56,000	28,000	127,000	336,000
19. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	350	375	350	380	625
@ 75% LOAD	325	350	325	360	570
@ 50% LOAD	300	325	300	340	540
20. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	27.5	55	27.5	95	92
@ 75% LOAD	20	42	20	65	69
@ 50% LOAD	14	30	14	44	46
21. FLY ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD					
DISPOSAL COST ($/TON)					
22. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD					
DISPOSAL COST ($/TON)					
23. EXHAUST DUCT DIMENSIONS @ STACK	76"	76"	76"	88"	150"
24. ELEVATION OF TIE IN POINT TO STACK					
25. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)					

a) Identify source of values (test or estimate)

Notes: Boiler 5 - Stacks 3&4
Boiler 6 - Stacks 4&5
Boiler 7 - Stack 6
Boiler 8 - Stack 7

E. I.D. FAN DATA

	Boiler number				
1. MAXIMUM STATIC HEAD (IN. W.G.)					
2. WORKING STATIC HEAD (IN. W.G.)					

Notes:

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES) 100
2. YEARS STORAGE (ASH ONLY) Soon to be discontinued.
3. DISTANCE FROM STACK (FT.) 12 miles
4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION
   a.
   b.
   c.
   d.
2. QUANTITY USED BY SEAM AND/OR MINE
   a.
   b.
   c.
   d.
3. ANALYSIS (19)
   HHV (BTU/LB)
   S (%)
   ASH (%)
   MOISTURE (%)
4. PPT PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA (1975)

1. TYPE #6 residual
2. S CONTENT (%) 1.3
3. ASH CONTENT (%) -
4. SPECIFIC GRAVITY 1
5. HHV (BTU/GAL) 145,628

I. NATURAL GAS HHV (BTU/FT^3)

J. COST DATA

ELECTRICITY

FUEL: COAL GAS OIL

WATER

STEAM

TAXES ON A.P.C. EQUIPMENT: STATE SALES

FEDERAL PROPERTY TAX

K. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE?

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE?

L. ADDITIONAL INFORMATION

F.E.A. LETTER

M. OIL/GAS TO COAL CONVERSION DATA

1. HAS THE BOILER EVER BURNED COAL?

Boiler No.	5	6	7	8	
Yes or No.	Yes	Yes	Yes	No	

2. SYSTEM AVAILABILITY

2.1 COAL HANDLING

		Yes	No
a.	Is the system still installed?	☒	☐
b.	Will it operate?	☐	☐

c. Of the following items which need to be replaced:

	Yes	No
Unloading equipment	☒	☐
Stack Reclaimer No rail service	☒	☐
Bunkers	☒	☐
Conveyors need extensive work	☒	☒
Scales corrosion	☒	☐
Coal Storage Area not enough room	☐	☒

2.2 FUEL FIRING

		Yes	No
a.	Is the system still installed?	☐	☐
b.	Will it operate?	☐	☐

c. Of the following items which need to be replaced:

	Yes	No
Pulverizers or Crushers Rebuilding	☒	☐
Feed Ducts	☒	☐
Fans modify	☒	☐
Controls	☒	☐

2.3 GAS CLEANING

		Yes	No
a.	Is the system still installed?	☒ 5	☒ 6,7
b.	Will it operate?	☒ 5	☒ 6,7

c. Of the following items which need to be replaced:

	Yes	No
Electrostatic Precipitator	☐	☐
Cyclones	☒	☐
Fly Ash Handling Equipment	☐	☐
Soot Blowers - Air Compressors	☐	☐
Wall deslaggers	☐	☐

2.4 ASH HANDLING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☒ ☐

c. Of the following items which need to be replaced:

	Yes	No
Bottom Ash Handling	☒	☐
Ash Pond	☒	☐

N. SUPPLEMENTARY CONTROL SYSTEM DATA

1. DOES THE PLANT NOW HAVE A SUPPLEMENTAL CONTROL SYSTEM (SCS)? Yes ☐ No ☐

   If yes, attach a description of the system.

2. IS THE PLANT CAPABLE OF SWITCHING TO LOW SULFUR FUELS? Yes ☐ No ☐

   2.1 Storage capacity for low sulfur fuels (tons, bbls, days)

   2.2 Bunkers available for low sulfur coal storage? Yes ☐ No ☐

   2.3 Handling facilities available for low sulfur fuels Yes ☐ No ☐

   If yes, describe ____________________

   ____

   2.4 Time required to switch fuels and fire the low sulfur fuel in the boiler (hrs)? ______

3. IS THE PLANT CAPABLE OF LOAD SHEDDING?

   If yes, discuss ____________________

   ____________________ Yes ☒ No ☐

4. IS THE PLANT CAPABLE OF LOAD SHIFTING?

   If yes, discuss ____________________

   ____________________ Yes ☒ No ☐

5. POWER PLANT MONITORING SYSTEM

   5.1 Existing system No SO_2 monitoring data available Yes ☐ No ☐

   a. Air quality instrumentation

	Number	Type
(1) Sulfur Oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulates - Intermittent	______	______
- Static	______	______

   (3) Other (describe) ____________

   b. Meteorological instrumentation

   If yes, describe ____________________

   ____

   c. Is the monitoring data available? Yes ☐ No ☐

   d. Is the monitoring data reduced and analyzed? Yes ☐ No ☐

   e. Provide map of monitoring locations

5.2 Proposed system Yes ☐ No ☐

If yes, describe and provide map ______

______

a. Air monitoring instrumentation

	Number	Type
(1) Sulfur oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulate		
- Intermittent	______	______
- Static	______	______

(3) Other (describe) ______

b. Meteorological instrumentation

If yes, describe ______

______

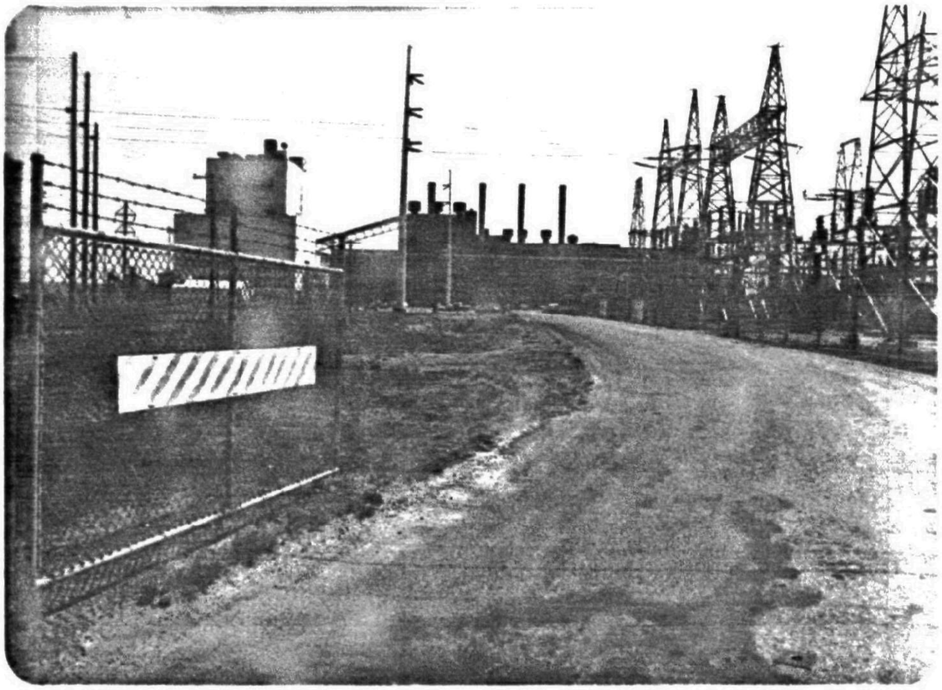


Photo No. 1. View from ground level at the entrance gate facing east showing the entire plant. Boiler No. 8 is on the left. The brick building houses Boilers 5, 6, and 7.

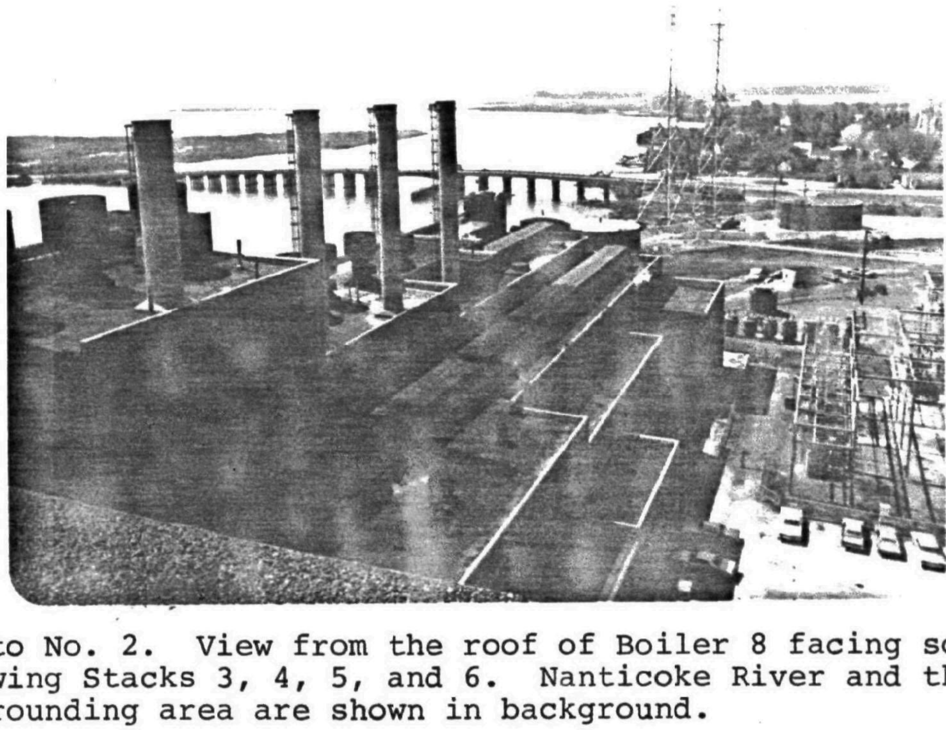


Photo No. 2. View from the roof of Boiler 8 facing south showing Stacks 3, 4, 5, and 6. Nanticoke River and the surrounding area are shown in background.

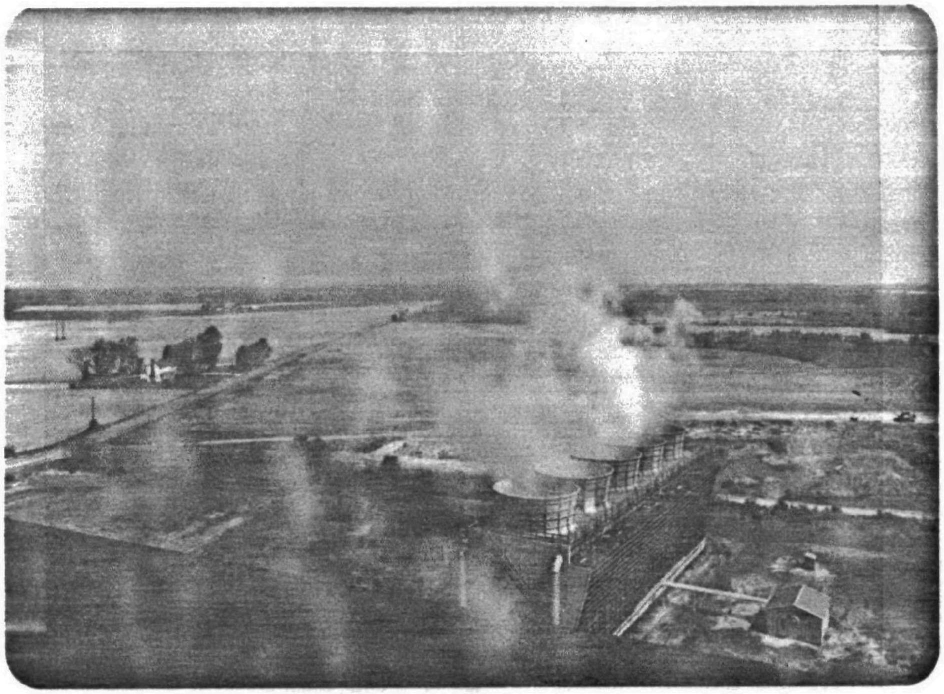


Photo No. 3. View from the roof of Boiler 8 facing north showing plant surroundings and cooling tower which serves Boiler 8.

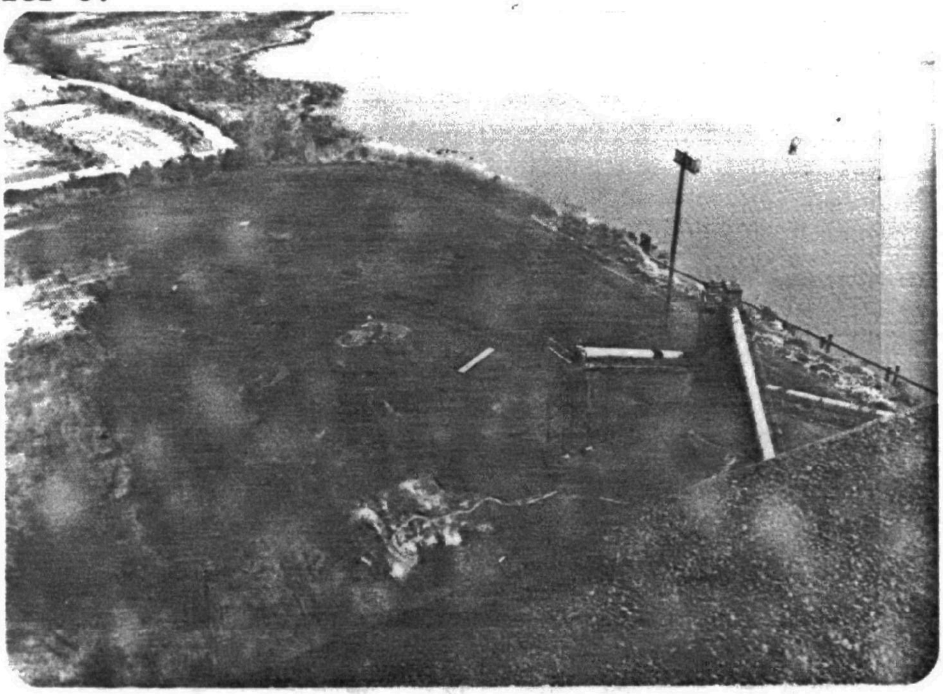


Photo No. 4. View from the roof of Boiler 8 facing north showing the coal storage area and coal handling facilities.

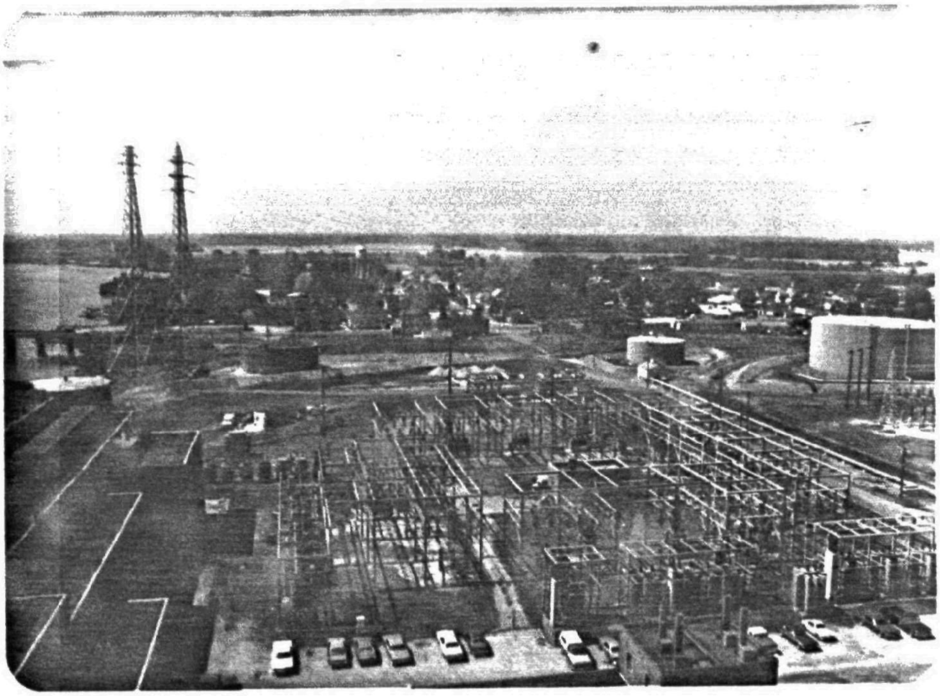


Photo No. 5. View from the roof of Boiler 8 facing south showing electrical substation and the oil storage tanks.

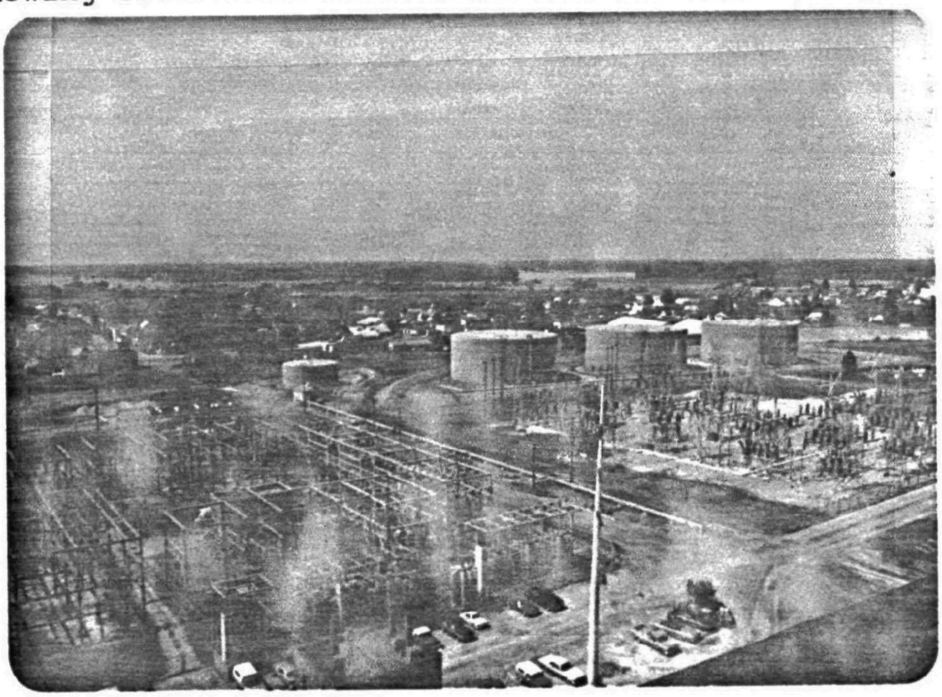


Photo No. 6. View from the roof of Boiler 8 facing southwest showing the electrical substation and the oil storage facilities.

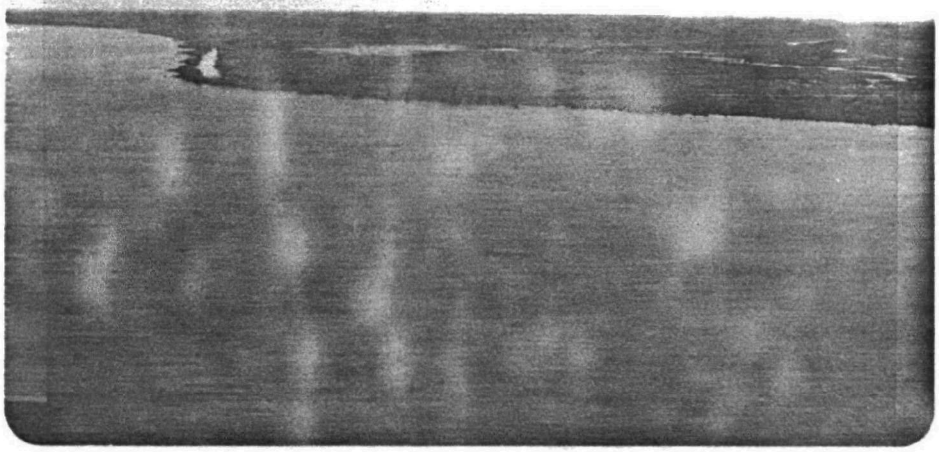


Photo No. 7. View from the roof of Boiler 8 facing east across Nanticoke River. The existing ash disposal facilities are located across the river.

Photo No. 8. View from the roof of Boiler 8 facing west showing the plant surroundings. The equipment storage buildings and areas are pictured in the foreground.

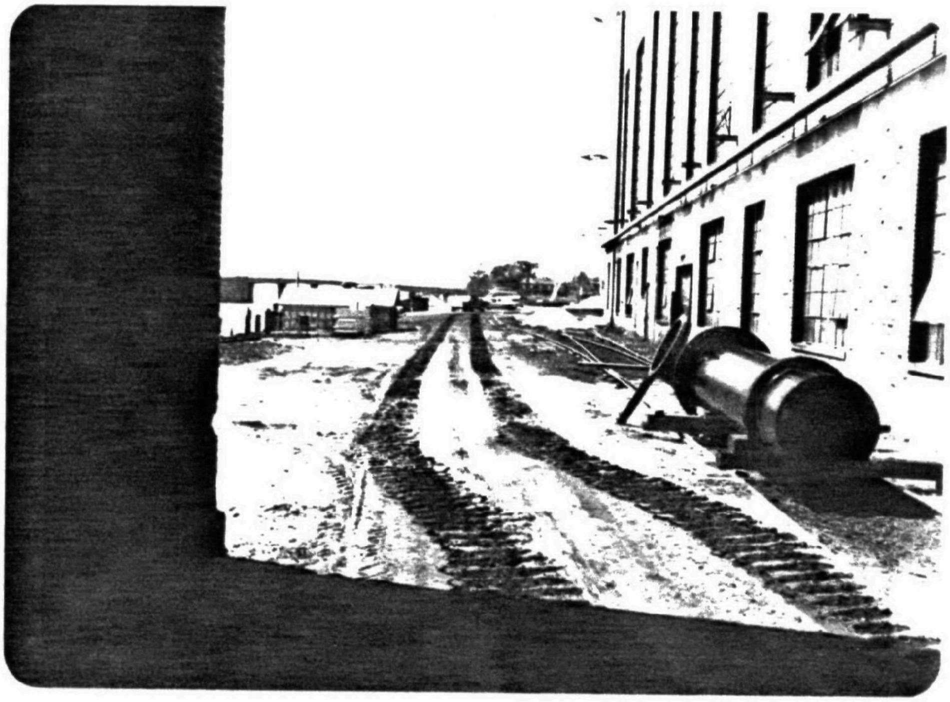


Photo No. 9. View from ground level facing south showing the space between the boiler house and the Nanticoke River.

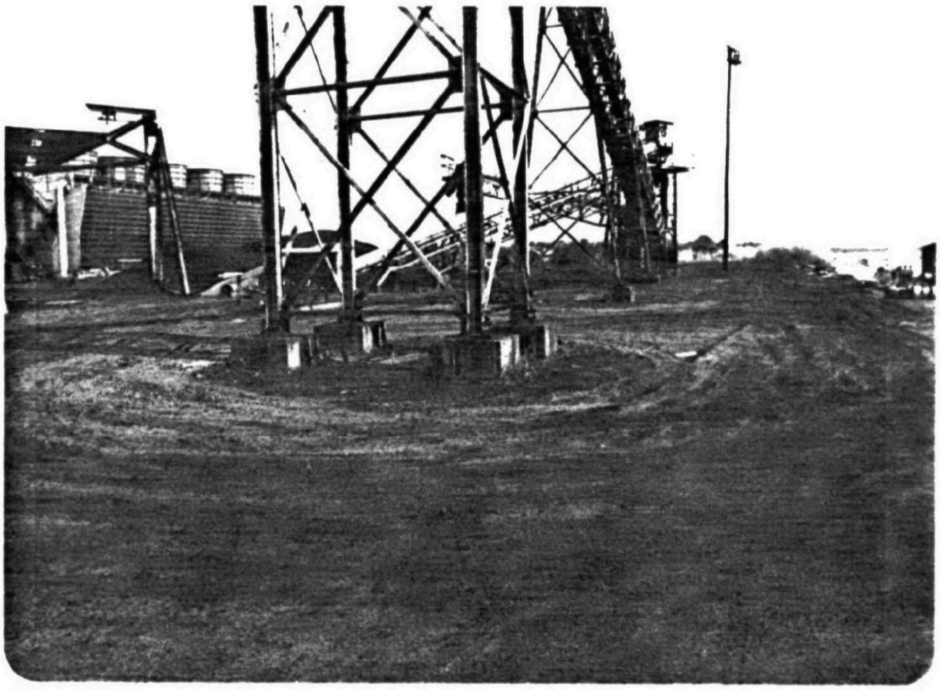


Photo No. 10. View from ground level facing north showing coal storage area, handling facilities, and the cooling tower serving Boiler 8.

TABLE R-1. ESTIMATED CAPITAL COST OF AN ELECTROSTATIC PRECIPITATOR FOR BOILER 7 AT THE VIENNA POWER PLANT (1978)

Direct Costs		
ESP		$ 1,495,000
Ash handling		124,000
Ducting		347,000
	Total direct costs	$ 1,966,000
Indirect Costs		
Interest during construction	8% of direct costs	$ 157,000
Contractor's fee	10% of direct costs	197,000
Engineering	6% of direct costs	118,000
Freight	1.25% of direct costs	25,000
Offsite	3% of direct costs	59,000
Taxes	1.5% of direct costs	29,000
Spares	1% of direct costs	20,000
Allowance for shakedown	3% of direct costs	59,000
Total indirect costs		$ 664,000
Contingency		526,000
Total		$ 3,156,000
Coal conversion costs		446,000
Grand total		$ 3,602,000
$/kW		90.05

TABLE R-2. ESTIMATED ANNUAL OPERATING COSTS OF AN ELECTROSTATIC PRECIPITATOR FOR BOILER 7 AT THE VIENNA POWER PLANT (1978)

Utilities	Quantity	Unit Cost	Annual Cost
Electricity	146 kW	27.55 mills/kWh	$ 6,000
Water	2660 10^3 gal/yr	$0.01/$10^3$ gal	1,000
Operating Labor			
Direct labor	0.5 man/shift	$8.50/man-hour	36,000
Supervision	15% of direct labor		5,000
Maintenance			
Labor and materials	2% of fixed investment		63,000
Supplies	15% of direct labor		5,000
Overhead			
Plant	50% of operation and maintenance		57,000
Payroll	20% of operating labor		8,000
Trucking			
Bottom/fly ash removal			1,932,000
Fixed Costs			
Depreciation	(7.69%)		
Interim replacement	(0.35%), Σ = 19.54% of fixed investment		
Insurance	(0.30%)		
Taxes	(0.00%)		
Capital cost	(11.20%)		
Total fixed cost			$ 617,000
Total cost			$2,734,000
Fuel credit			(997,000)
Net annual cost			$1,737,000
Mills/kWh			32.40

Table R-3 . ELECTROSTATIC PRECIPITATOR DESIGN VALUES FOR BOILER 7 AT THE VIENNA POWER PLANT

Design Parameter	Value
Collection efficiency, % (Overall)	96.2
Specific collecting area, ft^2/1000 acfm	202
Total collecting area, ft^2	48,900
Superficial velocity, fps	4
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	15x67x19

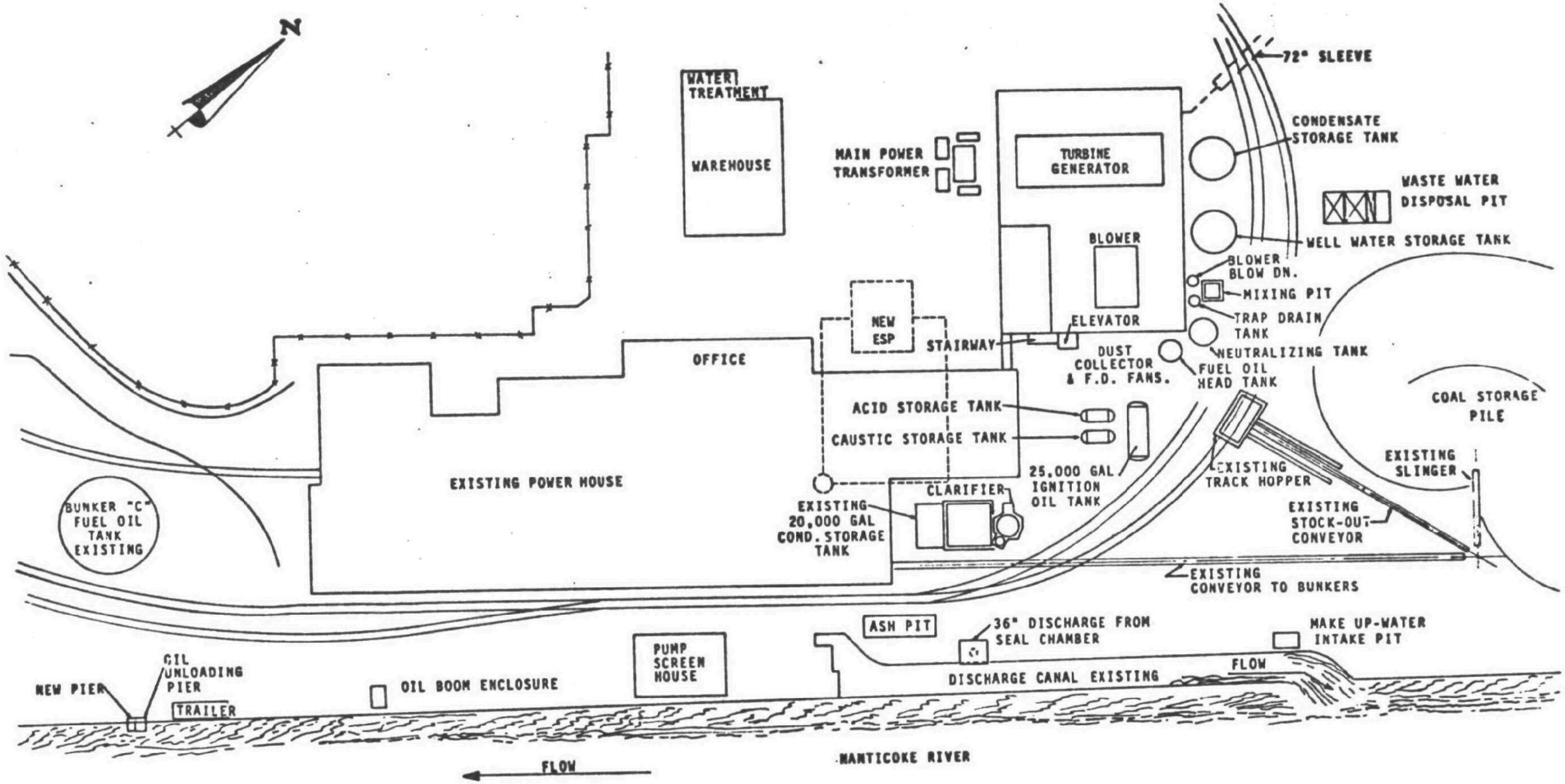


Figure R-1. Site plan showing possible location of a new ESP for Boiler 7 at the Vienna power plant.

APPENDIX S

WISDOM POWER PLANT

CONTENTS

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: CORN BELT POWER COOPERATIVE
2. MAIN OFFICE: 1300 North 13th St., Humbolt, Iowa 50548
3. RESPONSIBLE OFFICER: Dan C. Adams
4. POSITION: Supt. of Plants
5. PLANT NAME: Wisdom
6. PLANT LOCATION: Clay County, Iowa - Spencer, Iowa 5130
7. RESPONSIBLE OFFICER AT PLANT LOCATION: P. J. Rath
8. POSITION: Plant Superintendent
9. POWER POOL

DATE INFORMATION GATHERED: December 31, 1975

PARTICIPANTS IN MEETING:

Dan C. Adams - Corn Belt Power Cooperative
Philip J. Rath - Corn Belt Power Cooperative
John Metcalfe - Iowa Department of Environmental Quality
David A. Kirchgessner - U.S. Environmental Protection Agency
Thomas C. Ponder, Jr. - PEDCo Environmental, Inc.
N. David Noe - PEDCo Environmental, Inc.
Alan J. Sutherland - PEDCo Environmental, Inc.

	Boiler number				
	1				
B. ATMOSPHERIC EMISSIONS					
1. PARTICULATE EMISSIONS[a]					
* LB/MM BTU	.0109				
GRAINS/ACF					
LB/HR (FULL LOAD)					
TONS/YEAR ( )					
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION					
REGULATION & SECTION NO. Sect.	4.3 (2B)				
LB/MM BTU	.8				
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a]					
LB/MM BTU					
LB/HR (FULL LOAD)					
TONS/YEAR ( )					
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO. Sect.	4.3 (3a)				
LB/MM BTU	6.0				
b) FUTURE REQUIREMENT (DATE: 7/31/78)					
REGULATION & SECTION NO.	4.3 (3B)				
LB/MM BTU	5.0				

a) Identify whether results are from stack tests or estimates
* STW Testing Inc., Denver, Colorado (7/17/75) at 38 MW

	Boiler number				
15. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS					
MANUFACTURER	Hagen				
TYPE	multiple	cyclones			
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE: (GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER	American	Standard			
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)	99+				
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)	32,400				
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)	360°				
16. EXCESS AIR: DESIGN/ACTUAL (%)	20%				

Notes:

	Boiler number				
17. FLUE GAS RATE (ACFM)					
@ 100% LOAD	180,900				
@ 75% LOAD					
@ 50% LOAD					
18. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	350°				
@ 75% LOAD					
@ 50% LOAD					
19. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	59.78				
@ 75% LOAD					
@ 50% LOAD					
20. FLY ASH: TOTAL COLLECTED (TONS/YEAR)	500				
DISPOSAL METHOD	Silo → trucked				
DISPOSAL COST ($/TON)					
21. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR)					
1975 data DISPOSAL METHOD					
DISPOSAL COST ($/TON)					
22. EXHAUST DUCT DIMENSIONS @ STACK					
23. ELEVATION OF TIE IN POINT TO STACK					
24. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)	Oct. 1976 Turbine – Boiler for 3 weeks				

a) Identify source of values (test or estimate)

Notes: Breakdown cost (#21-22)

$540 - truck — 1/2 mile (1 way) to dump site
$1875 - labor
$1375 - tractor — $11,235 (cost for top & bottom)
$5100 - labor

E. I.D. FAN DATA	Boiler number				
1. MAXIMUM STATIC HEAD (IN. W.C.)					
2. WORKING STATIC HEAD (IN. W.C.)					

Notes:

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES) Unlimited
2. YEARS STORAGE (ASH ONLY) 20 years
3. DISTANCE FROM STACK (FT.) 1/2 mile
4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT No

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION

Mines & Location

a. 5 sources - districts 15, 22, 9
b. Dist. 15 - Welch Mine, Craig County, Okl.
c. Dist. 22 - Colstrip, Montana; Dist. 10 - Eagle Mine, Utah
d. Dist. 9 - Margareta, Hopkins County, Kentucky

2. QUANTITY USED BY SEAM AND/OR MINE

Total Coal → a. 42.87 consumption/1000 tons of coal

b.

Total Gas → c. 660.678 consumption/1000 mcf of gas

Analysis → d. 1,000 Btu/cf for gas

3. ANALYSIS (Avg) from 1975

GHV (BTU/LB) 12,015

S (%) 3%

ASH (%) 11.6

MOISTURE (%) 8.6

4. PPT PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA

1. TYPE
2. S CONTENT (%)
3. ASH CONTENT (%)
4. SPECIFIC GRAVITY
5. GHV (BTU/GAL)

I. COST DATA

ELECTRICITY

WATER

STEAM

J. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE?

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE?

K. OIL/GAS TO COAL CONVERSION DATA

1. HAS THE BOILER EVER BURNED COAL?

Boiler No.	1				
Yes or No.	Yes				

2. SYSTEM AVAILABILITY

2.1 COAL HANDLING

a. Is the system still installed? Yes ☒ No ☐

b. Will it operate? ☒ ☐

c. Of the following items which need to be replaced:

	Yes	No
Unloading equipment	☐	☒
Stack Reclaimer	☐	☒
Bunkers	☐	☒
Conveyors	☐	☒
Scales	☐	☒
Coal Storage Area	☐	☒

2.2 FUEL FIRING

a. Is the system still installed? Yes ☐ No ☐

b. Will it operate? ☐ ☐

c. Of the following items which need to be replaced:

	Yes	No
Pulverizers or Crushers	☐	☐
Feed Ducts	☐	☐
Fans	☐	☐
Controls	☐	☐

2.3 GAS CLEANING

a. Is the system still installed? Yes ☐ No ☐

b. Will it operate? ☐ ☐

c. Of the following items which need to be replaced:

	Yes	No
Electrostatic Precipitator	☐	☐
Cyclones	☐	☐
Fly Ash Handling Equipment	☐	☐
Soot Blowers - Air Compressors	☐	☐
Wall deslaggers	☐	☐

2.4 ASH HANDLING

		Yes	No
a.	Is the system still installed?	☐	☐
b.	Will it operate?	☐	☐
c.	Of the following items which need to be replaced:		
	Bottom Ash Handling	☐	☐
	Ash Pond	☐	☐

Milwaukee R.R. Line

Coal costs = $1.05 - $1.10/MW

L. SUPPLEMENTARY CONTROL SYSTEM DATA

1. DOES THE PLANT NOW HAVE A SUPPLEMENTAL CONTROL SYSTEM (SCS)? Yes ☐ No ☐

   If yes, attach a description of the system.

2. IS THE PLANT CAPABLE OF SWITCHING TO LOW SULFUR FUELS? Yes ☒ No ☐

   2.1 Storage capacity for low sulfur fuels (tons, bbls, days)

   2.2 Bunkers available for low sulfur coal storage? Derate Yes ☐ No ☐

   2.3 Handling facilities available for low sulfur fuels Yes ☐ No ☐

   If yes, describe ____________________

   ____

   2.4 Time required to switch fuels and fire the low sulfur fuel in the boiler (hrs)? ______

3. IS THE PLANT CAPABLE OF LOAD SHEDDING?

   If yes, discuss ____________________

   ____________________ Yes ☐ No ☐

4. IS THE PLANT CAPABLE OF LOAD SHIFTING?

   If yes, discuss ____________________

   ____________________ Yes ☐ No ☐

5. POWER PLANT MONITORING SYSTEM

   5.1 Existing system Yes ☐ No ☐

   a. Air quality instrumentation

	Number	Type
(1) Sulfur Oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulates - Intermittent	______	______
- Static	______	______

   (3) Other (describe) ____________

   b. Meteorological instrumentation

   If yes, describe ____________

   ____

   c. Is the monitoring data available? Yes ☐ No ☐

   d. Is the monitoring data reduced and analyzed? Yes ☐ No ☐

No env. complaints
ESP costs - $1.25 million

5.2 Proposed system Yes ☐ No ☐

If yes, describe ____________________

____

a. Air monitoring instrumentation

	Number	Type
(1) Sulfur oxides - Continuous	____	____
- Intermittent	____	____
- Static	____	____
(2) Suspended particulate		
- Intermittent	____	____
- Static	____	____

(3) Other (describe) ____________

b. Meteorological instrumentation

If yes, describe ____________

____

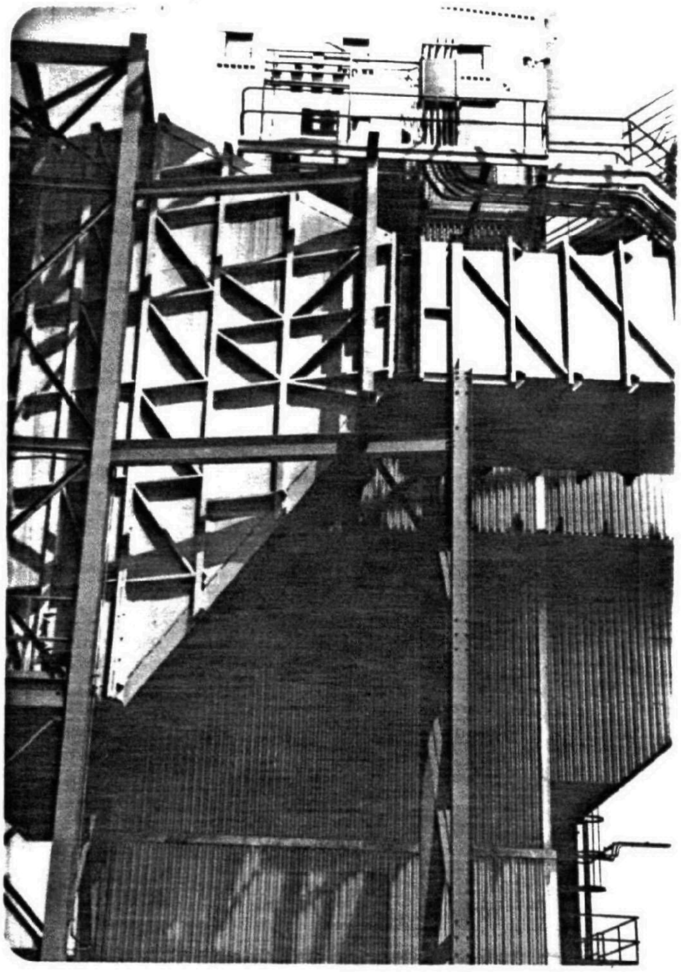


Photo No. 1. View from ground level facing northwest. The electrostatic precipitator and its tie-in ducts are shown in the center of the photograph.

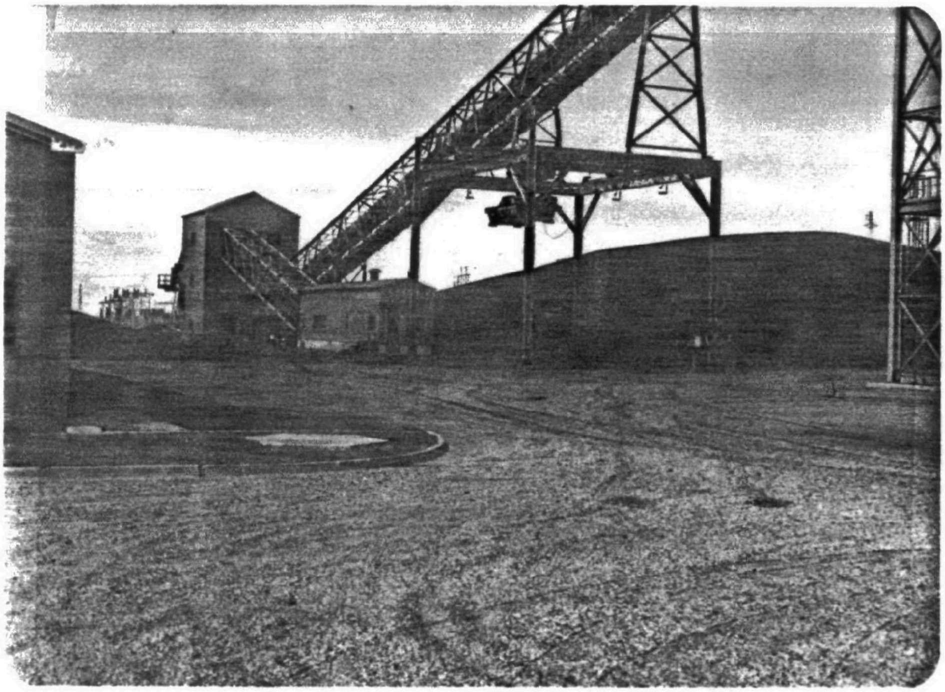


Photo No. 2. View from ground level facing southwest. The coal crusher, conveyor, coal pile, and coal car shaker are shown in the center of the photograph.

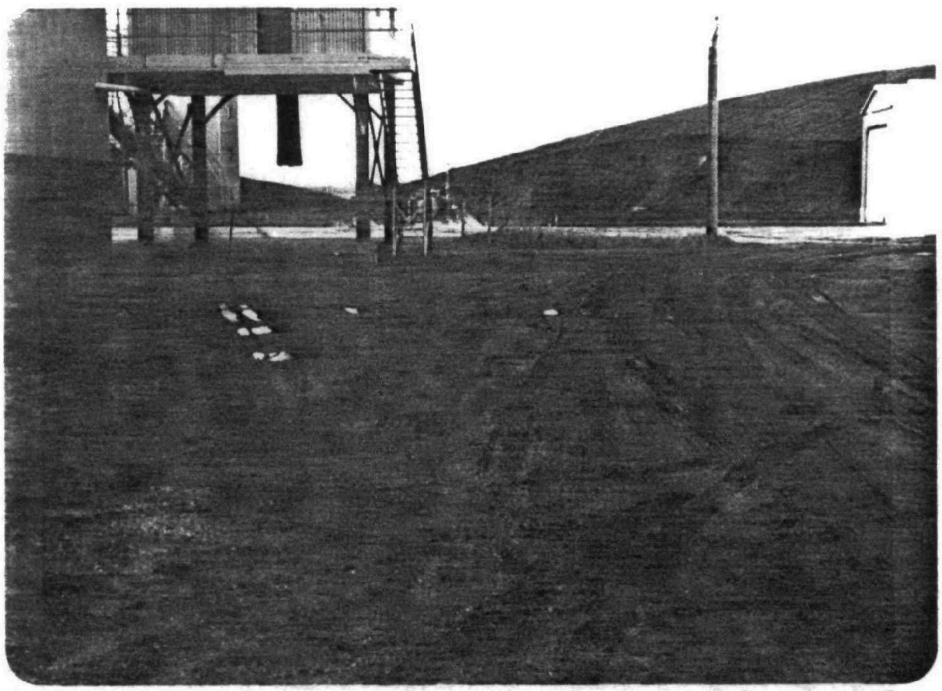


Photo No. 3. View from ground level looking southwest showing the ash silo and the coal pile.

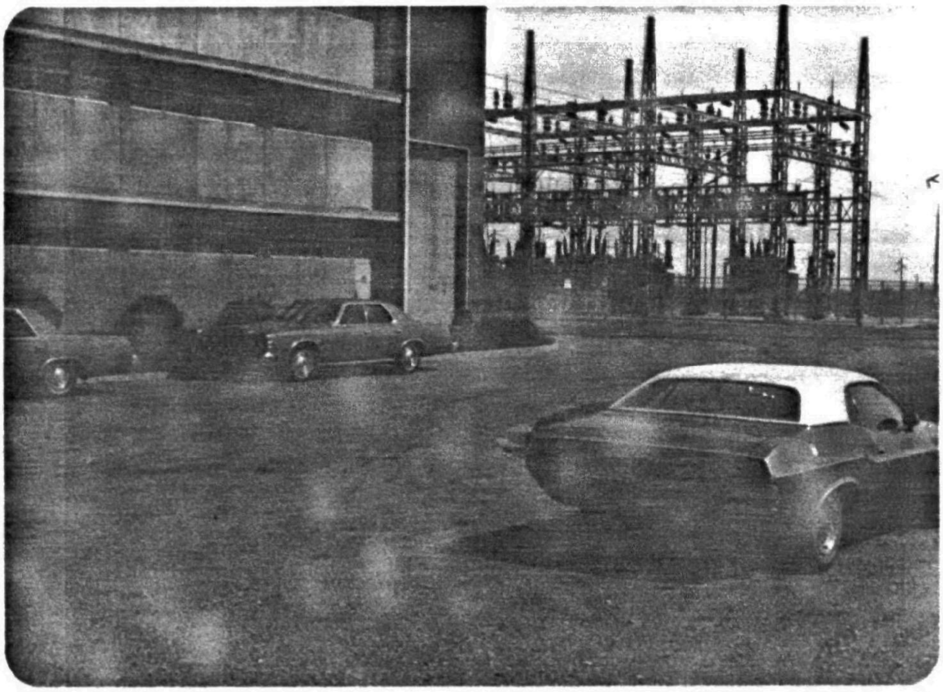


Photo No. 4. View from ground level looking northeast. The railroad spur is shown in the center of the photograph. A portion of the boiler house is located in the foreground and the electrical switchyard is shown in the background of the photograph.

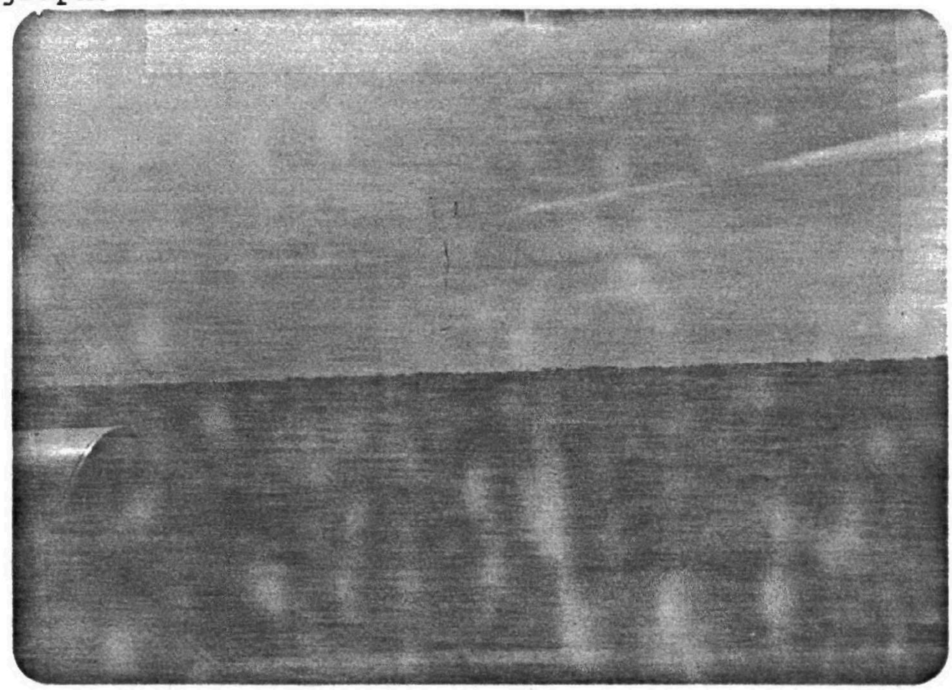


Photo No. 5. View from boiler house roof facing south showing the cooling tower and the surrounding area.

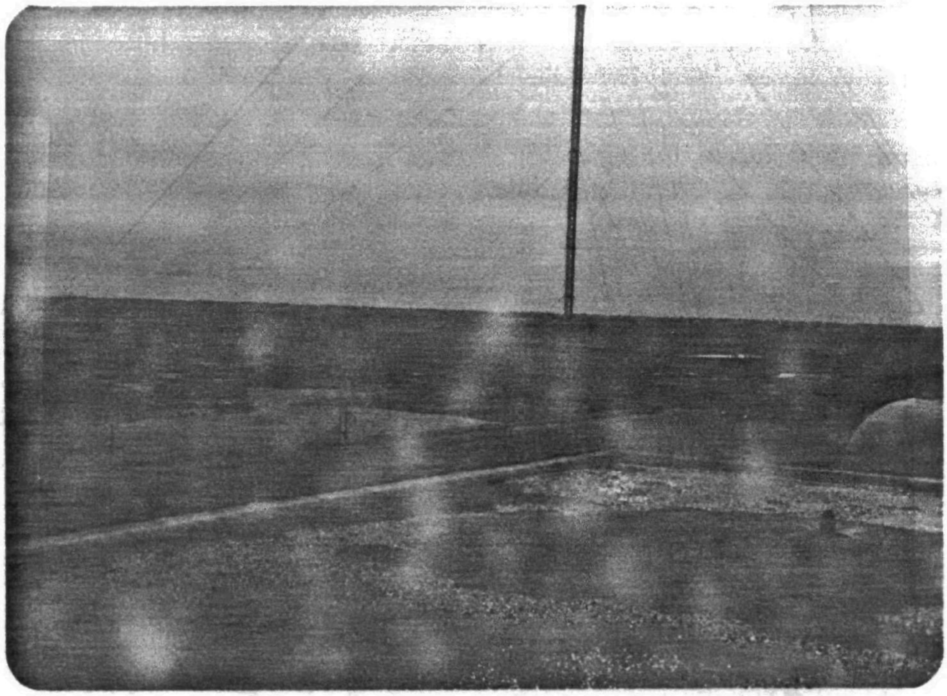


Photo No. 6. View from the boiler house foof looking east. The plant's access road and Stony Creek are shown in the center of the photograph.

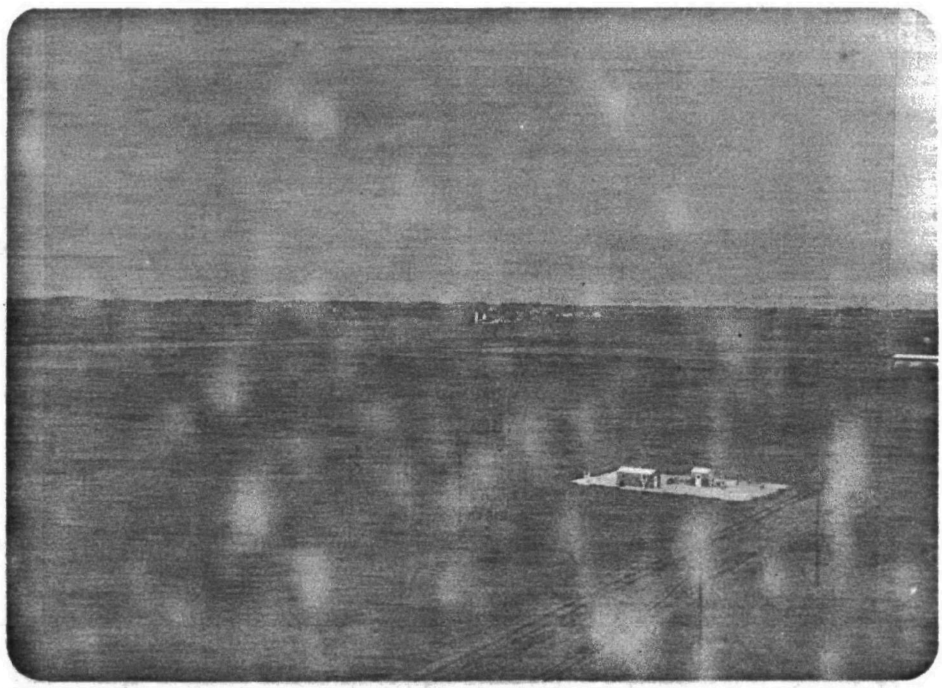


Photo No. 7. View from the boiler house roof facing west showing the main railroad spur and a natural gas meter and regulator station. The area surrounding the plant is shown in the background of the photograph.

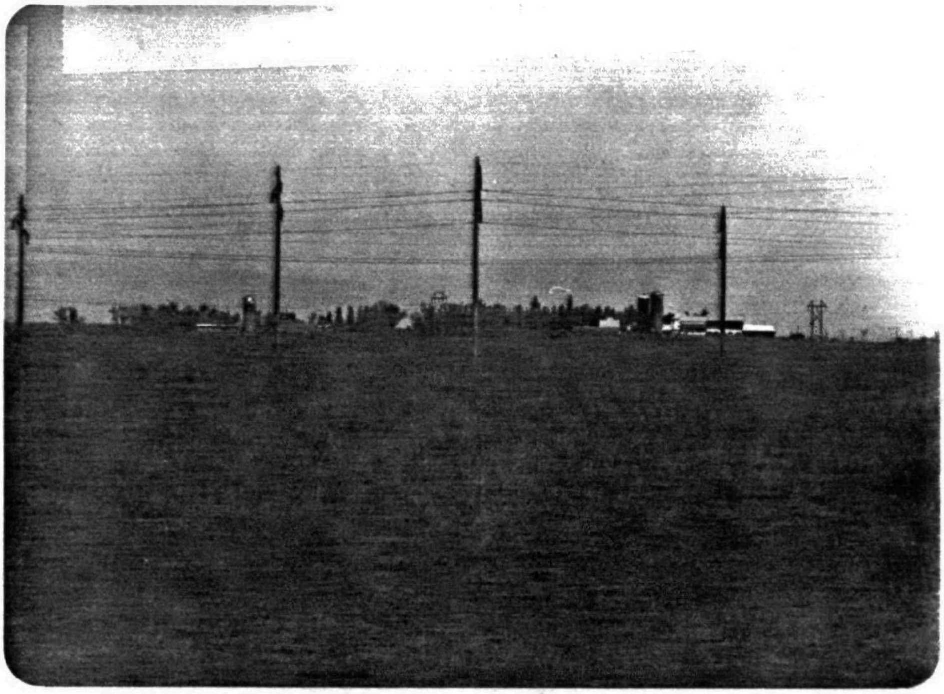


Photo No. 8. View from ground level looking north showing the plant's nearest neighbor.

Photo No. 9. View from the boiler house roof facing west showing the coal pile and the surrounding area.

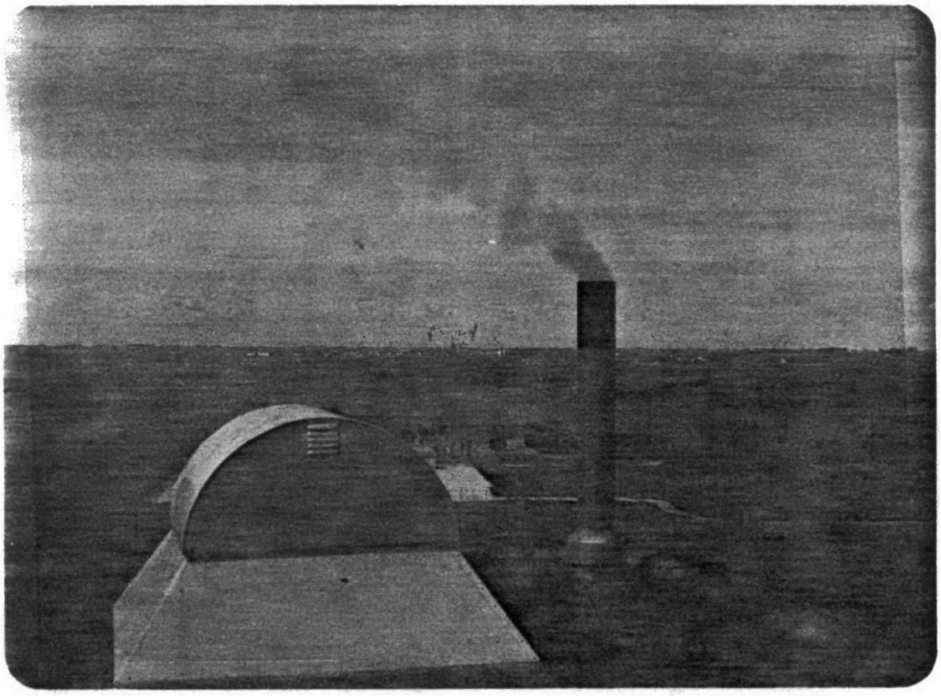


Photo No. 10. View from the boiler house roof facing southwest. The plant's switchyard and the surrounding area are shown in the background.

APPENDIX T

L.D. WRIGHT POWER PLANT

CONTENTS

FIGURES

TABLES

POWER PLANT SURVEY FORM

A. <u>COMPANY INFORMATION:</u>

1. COMPANY NAME: Department of Utilities
2. MAIN OFFICE: 725 N. Park; Fremont, Nebraska
3. RESPONSIBLE OFFICER: Wm. J. Sommers
4. POSITION: General Manager
5. PLANT NAME: Lon D. Wright Memorial
6. PLANT LOCATION: Fremont, Nebraska
7. RESPONSIBLE OFFICER AT PLANT LOCATION: Jess Williams
8. POSITION: Superintendent
9. POWER POOL Omaha Public Power District

DATE INFORMATION GATHERED: April 28, 1976

PARTICIPANTS IN MEETING:

Wm. J. Sommers	-	Department of Utilities
Forrest McGrew	-	Department of Utilities
Lyle Gill	-	City Attorney; Fremont, Nebraska
Daniel Wheeler	-	U.S. Environmental Protection Agency - Region VII
N. David Noe	-	PEDCo Environmental, Inc.
Robert Smolin	-	PEDCo Environmental, Inc.

B. ATMOSPHERIC EMISSIONS

		Boiler number				
		6	7			
1. PARTICULATE EMISSIONS[a] LB/MM BTU EST	Coal Gas	1.33 .005	1.33 .005			
GRAINS/ACF						
LB/HR (FULL LOAD)						
TONS/YEAR (1975) EST		213.8	285.6			
2. APPLICABLE PARTICULATE EMISSION REGULATION						
a) CURRENT REQUIREMENT						
AQCR PRIORITY CLASSIFICATION						
REGULATION & SECTION NO.						
LB/MM BTU		0.23	0.23			
b) FUTURE REQUIREMENT (DATE:)						
REGULATION & SECTION NO.						
LB/MM BTU		.18	.18	With new Boiler No. 8 in operation.		
3. SO_2 EMISSIONS[a] LB/MM BTU EST	Coal Gas	1.29 0.0006	1.29 0.0006			
LB/HR (FULL LOAD)						
TONS/YEAR (1975) EST		207.6	276.8			
4. APPLICABLE SO_2 EMISSION REGULATION						
a) CURRENT REQUIREMENT						
REGULATION & SECTION NO.						
LB/MM BTU		2.5	2.5			
b) FUTURE REQUIREMENT (DATE:)						
REGULATION & SECTION NO.						
LB/MM BTU						

de fy th es s fr sta te or ti s

C. SITE DATA

1. U.T.M. COORDINATES Lat. 41°-26'-13", Long. 96°-27'-17"
2. ELEVATION ABOVE MEAN SEA LEVEL (FT) 1,176.74
3. SOIL DATA: BEARING VALUE ______

   PILING NECESSARY No - On slab
4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA
5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE)
6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): ______

D. BOILER DATA

	Boiler number 6	7			
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK	Floating	Floating			
2. TOTAL HOURS OPERATION (19 75)	6,456	6,709			
3. AVERAGE CAPACITY FACTOR (19 75)	46%	45%			
4. SERVED BY STACK NO.	6	7			
5. BOILER MANUFACTURER	B&W*	ERIG+			
6. YEAR BOILER PLACED IN SERVICE	1957	1963			
7. REMAINING LIFE OF UNIT (years)	21	27			
8. GENERATING CAPACITY (MW)					
RATED	18.5	28.5			
MAXIMUM CONTINUOUS (Coal)	15	20			
PEAK					
9. FUEL CONSUMPTION:					
COAL (TPH) RATED					
MAXIMUM CONTINUOUS	8.3	13.2			
PEAK					
10. ACTUAL FUEL CONSUMPTION					
COAL (TPY) (19 75)	15,600	20,800			
GAS (19 75) MCF	388,400	771,129			
11. WET OR DRY BOTTOM	Wet	Wet			
12. FLY ASH REINJECTION (YES OR NO)	No	No			
13. STACK HGT ABOVE GRADE (FT.)	176	176			
14. I.D. OF STACK AT TOP (INCHES)	96	120			

Notes: * B&W - Babcock & Wilcox
+ ERIG - Erie City Iron Works

	Boiler number				
	6	7			
15. FLUE GAS CLEANING EQUIPMENT					
a) MECHANICAL COLLECTORS					
MANUFACTURER	West	West			
TYPE	SCTA	SCTA			
EFFICIENCY: DESIGN/ACTUAL (%)	81/70	81/70			
MASS EMISSION RATE: (GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER	N.A.	N.A.			
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)					
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)					
16. EXCESS AIR: DESIGN/ACTUAL (%)	20	20			

Notes:

	Boiler number				
	6	7			
17. FLUE GAS RATE (ACFM)					
@ 100% LOAD	66,100	101,500			
@ 75% LOAD					
@ 50% LOAD					
18. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	335	338			
@ 75% LOAD					
@ 50% LOAD					
19. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	275	330			
@ 75% LOAD	295	300			
@ 50% LOAD	300	290			
20. FLY ASH: TOTAL COLLECTED (TONS/YEAR)	770				
DISPOSAL METHOD	Land Fill				
DISPOSAL COST ($/TON)					
21. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR)	200				
DISPOSAL METHOD	Land Fill				
DISPOSAL COST ($/TON)					
22. EXHAUST DUCT DIMENSIONS @ STACK	8'-0"x 3'-8 1/2"	7'-0" x 5'-6"			
23. ELEVATION OF TIE IN POINT TO STACK	91'	91'			
24. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)	1978	1978			

a) Identify source of values (test or estimate)

Notes:

E. I.D. FAN DATA

	Boiler number				
1. MAXIMUM STATIC HEAD (IN. W.C.)					
2. WORKING STATIC HEAD (IN. W.C.)					

Notes:

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES) 5

2. YEARS STORAGE (ASH ONLY) Yearly maintenance

3. DISTANCE FROM STACK (FT.)

4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION

a.

b.

c.

d.

2. QUANTITY USED BY SEAM AND/OR MINE

a.

b.

c.

d.

3. ANALYSIS

GHV (BTU/LB) 10,300

S (%) 0.7

ASH (%) 7.0

MOISTURE (%) 12.5

4. PPT PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA

1. TYPE

2. S CONTENT (%)

3. ASH CONTENT (%)

4. SPECIFIC GRAVITY

5. GHV (BTU/GAL)

I. COST DATA

ELECTRICITY

WATER

STEAM

J. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE? Would need enlargement.

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE?

K. OIL/GAS TO COAL CONVERSION DATA

1. HAS THE BOILER EVER BURNED COAL?

Boiler No.	6	7			
Yes or No.	Yes	Yes			

2. SYSTEM AVAILABILITY

2.1 COAL HANDLING

	Yes	No	
a. Is the system still installed?	☒	☐	
b. Will it operate?	☒	☐	

c. Of the following items which need to be replaced:

		Yes	No	
Unloading equipment		☐	☒	Frozen
Stack Reclaimer	NA	☐	☐	Coal
Bunkers		☐	☒	Problem
Conveyors		☐	☒	
Scales		☐	☒	
Coal Storage Area		☐	☒	

2.2 FUEL FIRING

	Yes	No
a. Is the system still installed?	☒	☐
b. Will it operate?	☒	☐

c. Of the following items which need to be replaced:

	Yes	No
Pulverizers or Crushers	☐	☒
Feed Ducts	☐	☒
Fans	☐	☒
Controls	☐	☒

2.3 GAS CLEANING

	Yes	No
a. Is the system still installed?	☒	☐
b. Will it operate?	☒	☐

c. Of the following items which need to be replaced:

		Yes		No	
Electrostatic Precipitator	NA	☐		☐	
Cyclones		☒		☐	
Fly Ash Handling Equipment		☒	Modify	☐	
Soot Blowers - Air Compressors		☐		☒	May be
Wall deslaggers		☐		☒	requir-ed.

2.4 ASH HANDLING

		Yes	No
a.	Is the system still installed?	☒	☐
b.	Will it operate?	☒	☐
c.	Of the following items which need to be replaced:		
	Bottom Ash Handling	☒	☐
	Ash Pond	☒	☐

L. SUPPLEMENTARY CONTROL SYSTEM DATA

1. DOES THE PLANT NOW HAVE A SUPPLEMENTAL CONTROL SYSTEM (SCS)? Yes [ ] No [X]

   If yes, attach a description of the system.

2. IS THE PLANT CAPABLE OF SWITCHING TO LOW SULFUR FUELS? Yes [X] No [ ]

   2.1 Storage capacity for low sulfur fuels (tons, bbls, days)

   2.2 Bunkers available for low sulfur coal storage? Yes [X] No [ ]

   2.3 Handling facilities available for low sulfur fuels Yes [X] No [ ]

   If yes, describe ______________________

   ____

   2.4 Time required to switch fuels and fire the low sulfur fuel in the boiler (hrs)? N.A.

3. IS THE PLANT CAPABLE OF LOAD SHEDDING?

   If yes, discuss ______________________

   ______________________ Yes [ ] No [X]

4. IS THE PLANT CAPABLE OF LOAD SHIFTING?

   If yes, discuss ______________________

   ______________________ Yes [ ] No [X]

5. POWER PLANT MONITORING SYSTEM

   5.1 Existing system Yes [ ] No [ ]

   a. Air quality instrumentation

	Number	Type
(1) Sulfur Oxides - Continuous	______	______
- Intermittent	______	______
- Static	______	______
(2) Suspended particulates		
- Intermittent	______	______
- Static	______	______

   (3) Other (describe)____________

   b. Meteorological instrumentation

   If yes, describe ______________________

   ____

   c. Is the monitoring data available? Yes [ ] No [ ]

   d. Is the monitoring data reduced and analyzed? Yes [ ] No [ ]

5.2 Proposed system — Yes ☐ No ☐

If yes, describe ______________________

____

a. Air monitoring instrumentation

	Number	Type
(1) Sulfur oxides - Continuous	____	____
- Intermittent	____	____
- Static	____	____
(2) Suspended particulate		
- Intermittent	____	____
- Static	____	____

(3) Other (describe) ____________

b. Meteorological instrumentation

If yes, describe ________________

____

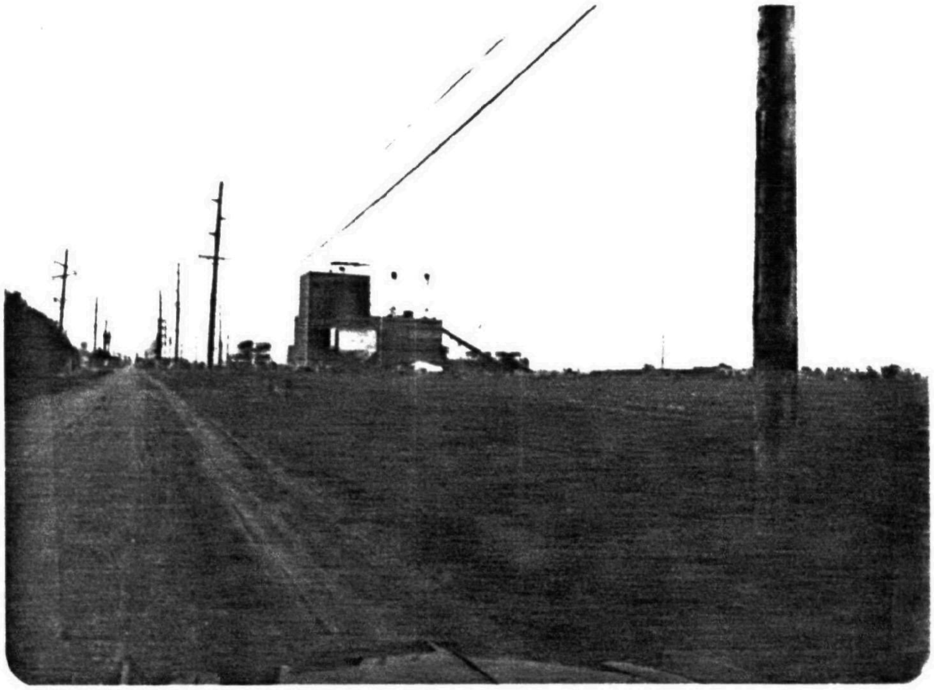


Photo No. 1. View from ground level facing west showing the Lon D. Wright Power Plant.

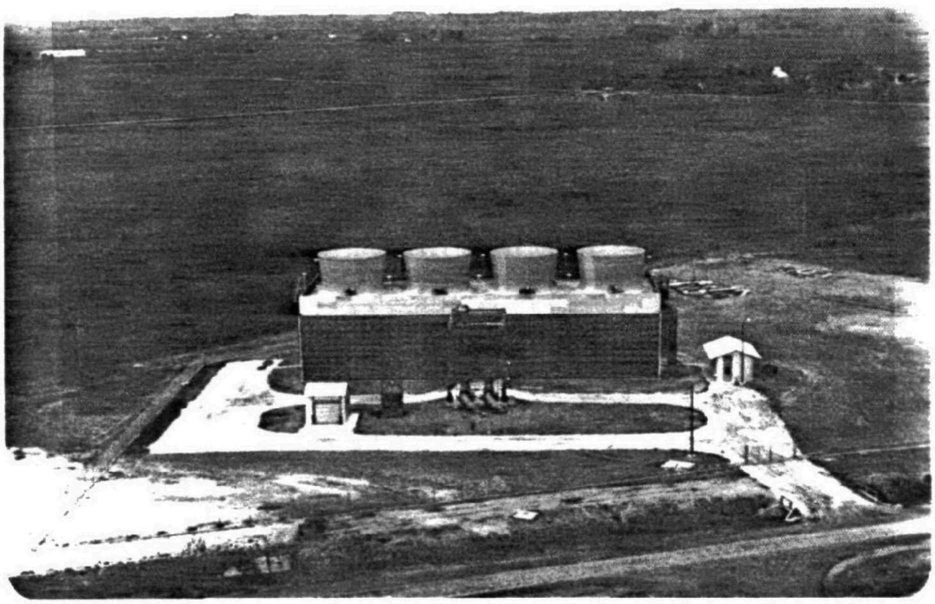


Photo No. 2. View from the boiler house roof facing northeast showing the cooling tower and the surrounding area.

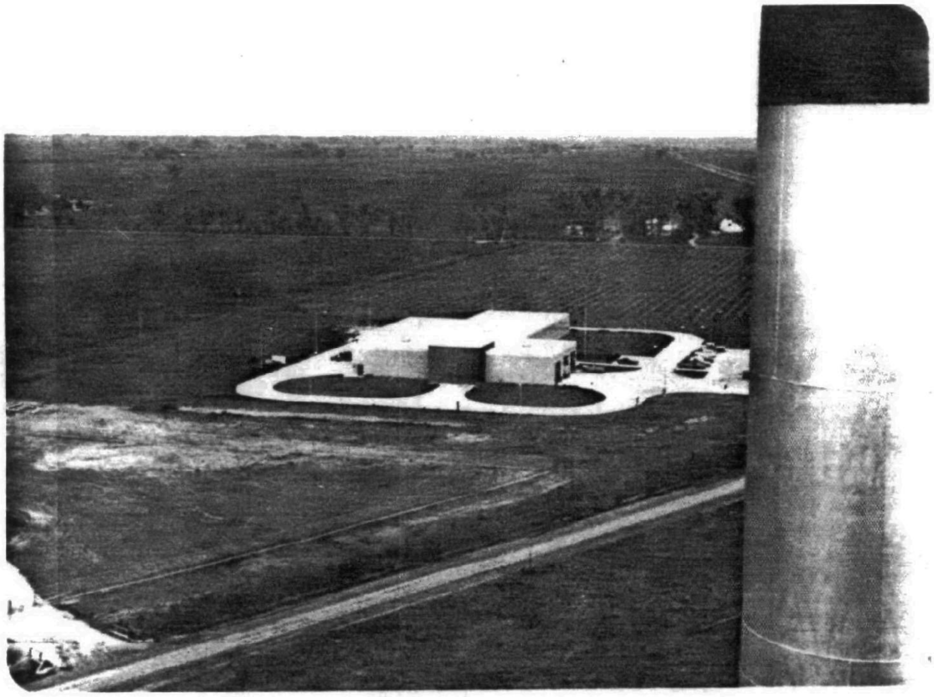


Photo No. 3. View from the boiler house roof facing east showing the warehouse and the surrounding area.

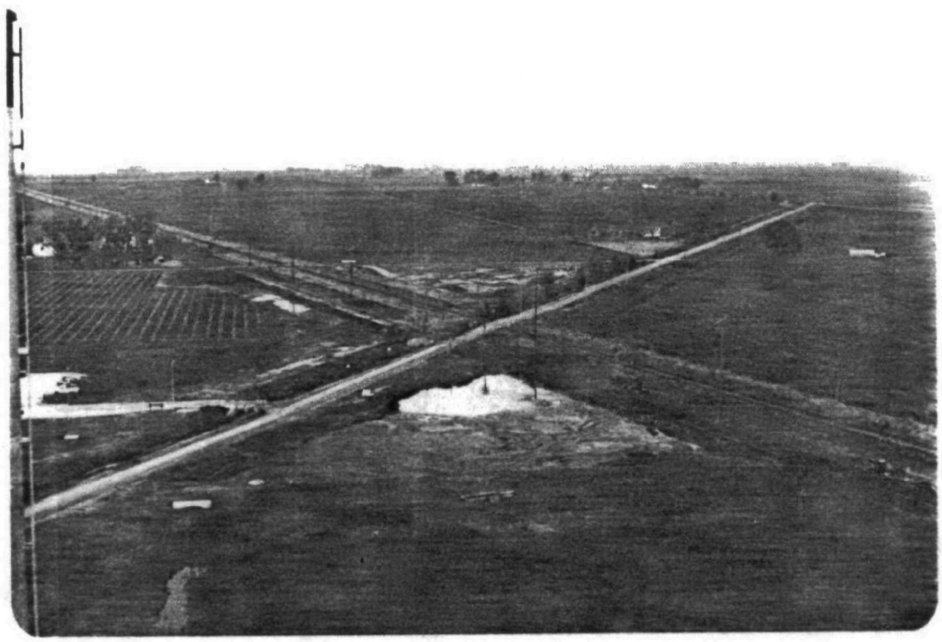


Photo No. 4. View from the boiler house roof facing south-east showing the ash pond and part of the coal storage area. In the background, the surrounding area is shown.

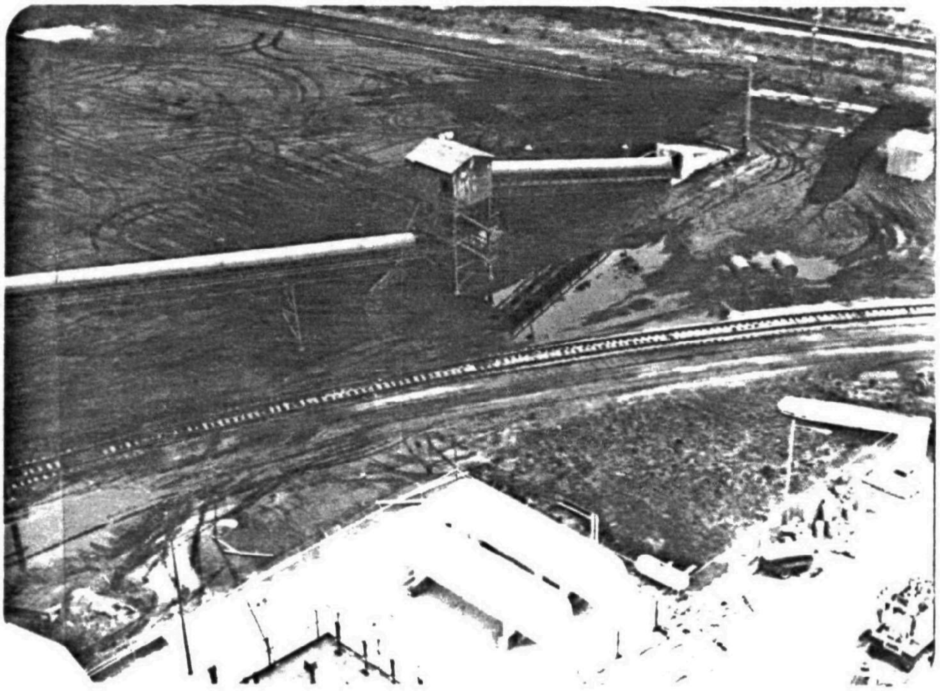


Photo No. 5. View from the boiler house roof facing southeast showing the crusher house and part of the coal storage area.

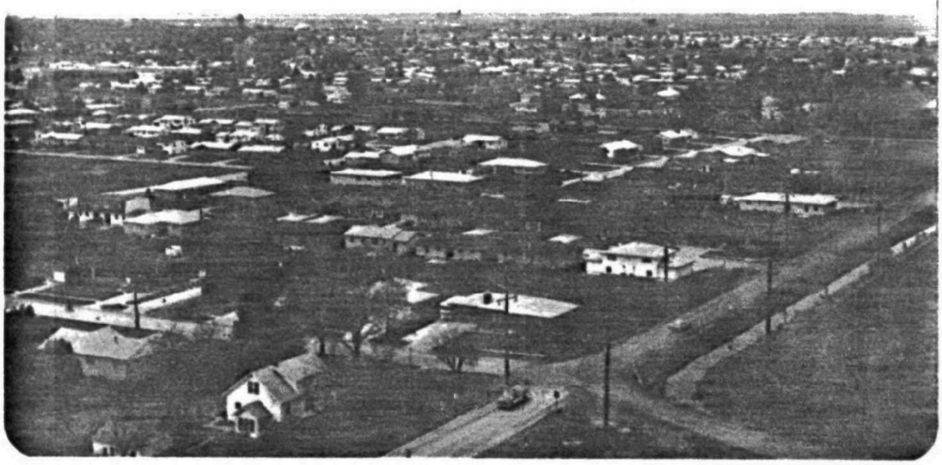


Photo No. 6. View from the boiler house roof facing northwest showing the surrounding residential area.

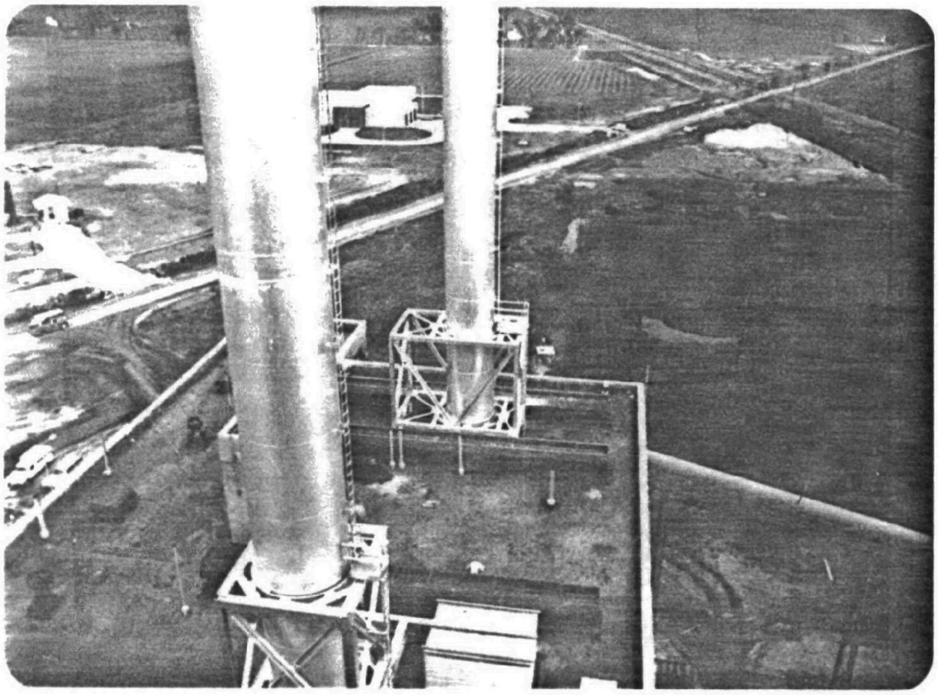


Photo No. 7. View from the boiler house roof facing southeast showing stacks 6 and 7 and the ash ponds.

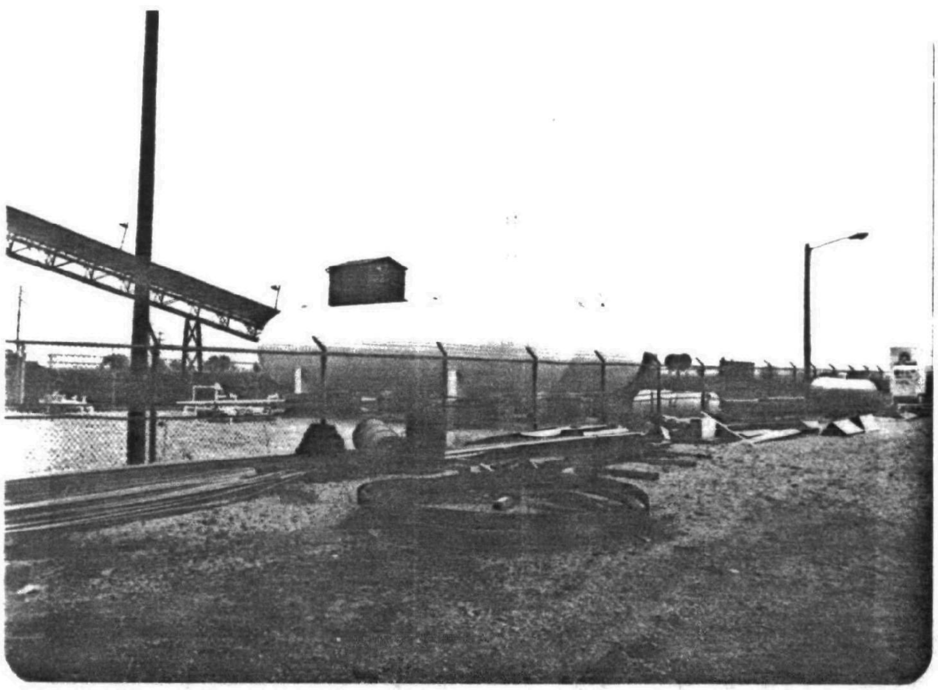


Photo No. 8. View from ground level facing southeast showing the propane tank farm.

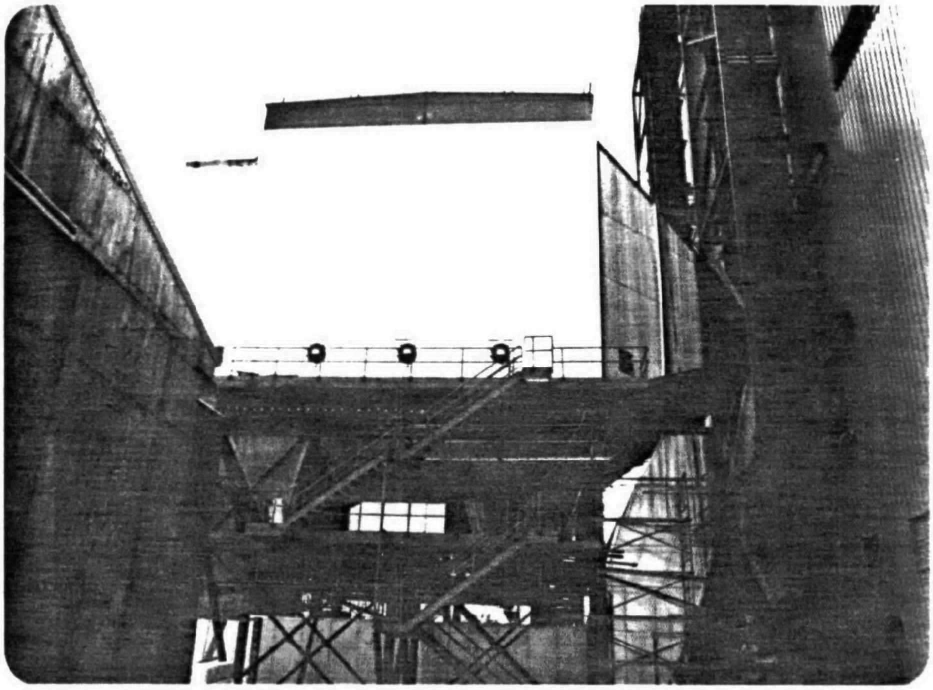


Photo No. 9. View from ground level facing west showing the ESP for Boiler 8.

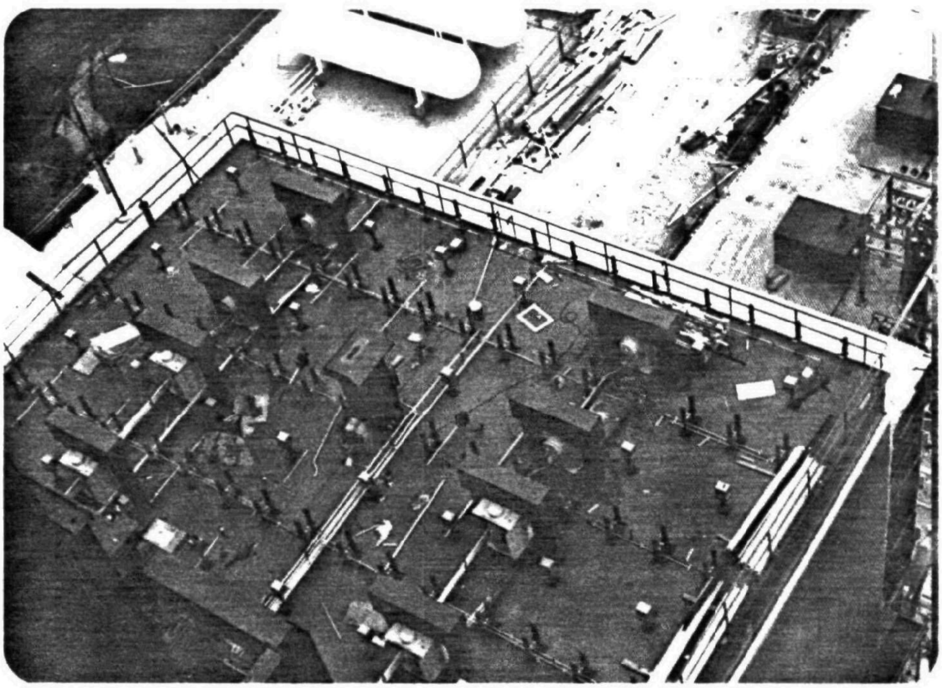


Photo No. 10. View from the boiler house roof facing south showing the top of the ESP for Boiler 8.

TABLE T-1. ESTIMATED CAPITAL COST OF ELECTROSTATIC PRECIPITATORS FOR BOILERS 6 AND 7 AT THE L. D. WRIGHT POWER PLANT (1978)

Direct Costs		
ESP		$ 2,208,000
Ash handling		183,000
Ducting		259,000
	Total direct costs	$ 2,650,000
Indirect Costs		
Interest during construction	8% of direct costs	$ 212,000
Contractor's fee	10% of direct costs	265,000
Engineering	6% of direct costs	159,000
Freight	1.25% of direct costs	33,000
Offsite	3% of direct costs	80,000
Taxes	1.5% of direct costs	40,000
Spares	1% of direct costs	27,000
Allowance for shakedown	3% of direct costs	80,000
Total indirect costs		$ 896,000
Contingency		709,000
Total		$ 4,255,000
Coal conversion costs		475,000
Grand total		$ 4,730,000
$/kW		135.14

TABLE T-2. ESTIMATED ANNUAL OPERATING COSTS OF ELECTROSTATIC PRECIPITATORS FOR BOILERS 6 AND 7 AT THE L. D. WRIGHT POWER PLANT (1978)

Utilities	Quantity	Unit Cost	Annual Cost
Electricity	216 kW	27.5 mills/kWh	$ 24,000
Water	2911 10^3 gal/yr	$0.01/$10^3$ gal	1,000
Operating Labor			
Direct labor	0.5 man/shift	$8.50/man-hour	73,000
Supervision	15% of direct labor		11,000
Maintenance			
Labor and materials	2% of fixed investment		85,000
Supplies	15% of labor and materials		13,000
Overhead			
Plant	50% of operation and maintenance		91,000
Payroll	20% of operating labor		17,000
Coal Cost Differentials			
Operating and maintenance			83,000
Fixed Costs			
Depreciation	(4.55%)		
Interim replacement	(0.35%), Σ = 16.40% of fixed investment		
Insurance	(0.30%)		
Taxes	(0.00%)		
Capital cost	(11.20%)		
Total fixed cost			$ 698,000
Total cost			$ 1,096,000
Fuel cost			118,000
Net annual cost			$ 1,214,000
Mills/kWh			8.70

Table T-3. ELECTROSTATIC PRECIPITATOR DESIGN VALUES FOR BOILER 6 AT THE L.D. WRIGHT POWER PLANT

Design Parameter	Value
Collection efficiency, % (Overall)	96.9
Specific collecting area, ft^2/1000 acfm	431
Total collecting area, ft^2	28,500
Superficial velocity, fps	4
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	30 x 9 x 47

Table T-4. ELECTROSTATIC PRECIPITATOR DESIGN VALUES FOR BOILER 7 AT THE L.D. WRIGHT POWER PLANT

Design Parameter	Value
Collection efficiency, % (Overall)	96.9
Specific collecting area, ft^2/1000 acfm	431
Total collecting area, ft^2	44,000
Superficial velocity, fps	4
Overall ESP dimensions (height x width x depth), ft excluding hopper dimensions	30 x 14 x 46

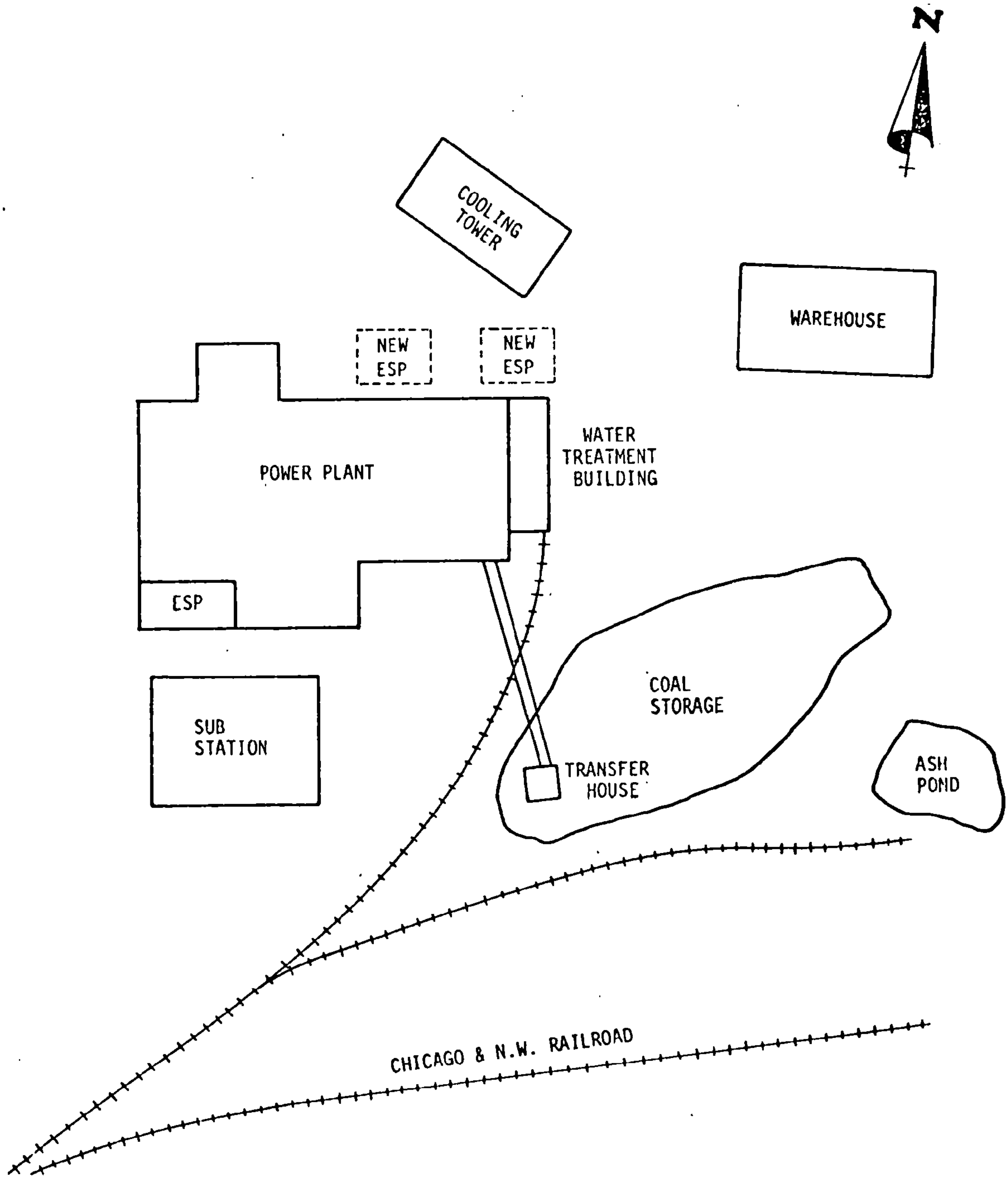


Figure T-1. Site plan showing possible locations of new ESP's for Boilers 6 and 7 at the L.D. Wright power plant.

APPENDIX U

BASIS OF SODIUM SOLUTION REGENERABLE PROCESS DESIGN

APPENDIX U

BASIS OF SODIUM SOLUTION REGENERABLE PROCESS DESIGN

A. DESIGN VALUES

The design basis for the sodium solution regenerable system was determined after review of process designs now in use or proposed for use, and discussions with Davy Power Gas. A process flow sheet is presented in Figure U-1. A list of equipment required for the sodium solution regenerable process is shown in Table U-1.

Values of the major design parameters are tabulated below:

- Variable design parameters: Table U-2
- Constant design parameters: Tables U-3 and U-4
- Flue gas pressure: atmospheric
- Reheat: 50°F above dew point (from 125 to 175°F)
- Soda ash consumption: 5% stoichiometric

Soda Ash System

Size: (unloading hoppers for the twenty plants): 200 tons

Feeders: capacity = 3.0 x maximum soda ash flow

Na_2CO_3 slurry storage tank: 4 hours

Na_2CO_3 slurry feed pump: 1 pump

Raw water pumps: two

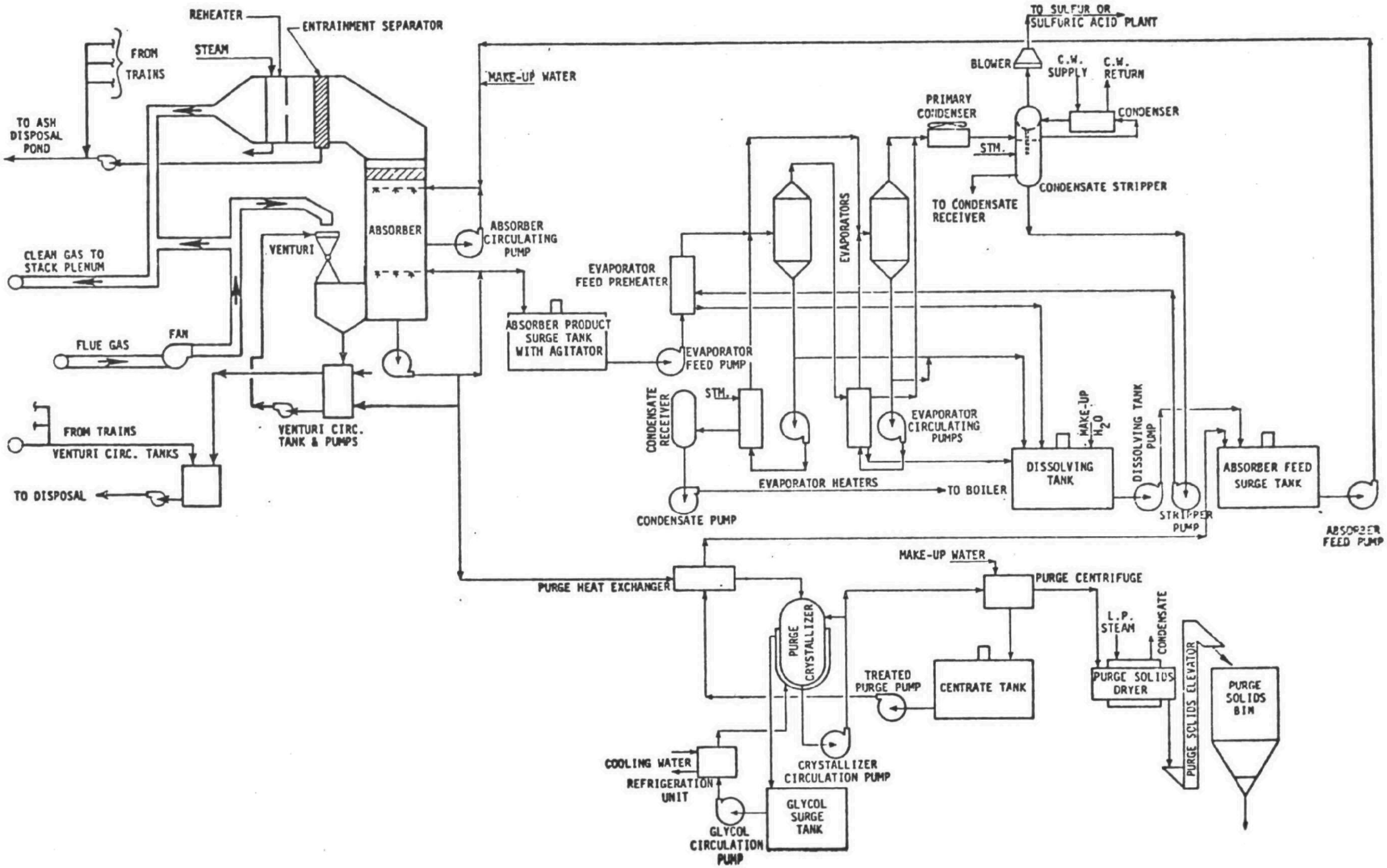


Figure U-1. Sodium solution regenerable system.

COMPANY ______________ EQUIPMENT LIST P.N. ______________

PEDCo-ENVIRONMENTAL
Cincinnati, Ohio

LOCATION ______________ CHECKED BY ______________ DATE ______

Sodium Solution Regenerable

COMPUTED BY ______________ DATE ______

Table U-1. EQUIPMENT LIST FOR THE SODIUM SOLUTION REGENERABLE SYSTEM

ITEM NO.	DESCRIPTION	NO. OF ITEMS	H.P/ ITEM	TOTAL H.P.	COST/ ITEM	TOTAL COST
	$NaCO_3$ Preparation System					
WL-P1	Storage Silo					
WL-P2	Vibrating Feeder					
WL-P3	Na_2CO_3 Dissolving Tank					
WL-P4	Na_2CO_3 Agitator					
WL-P5	Na_2CO_3 Make-up Pump					
	SO_2 Scrubbing System					
WL-S1	SO_2 Absorber					
WL-S2	Absorber Circulation Pumps					
WL-S3	I.D. Fan					
WL-S4	Heat Exchanger					
WL-S5	Soot Blower					
WL-S6	Butterfly Valving					
WL-S7	Absorber Feed Surge Tank					
WL-S8	Absorber Feed Surge Tank Agitator					
WL-S9	Ducting					
WL-S10	Absorber Product Surge Tank					
WL-S11	Absorber Product Surge Tank Agitator					
	Purge Treatment					
WL-PT1	Purge Stream Heat Exchanger					
WL-PT2	Refrigeration Unit					
WL-PT3	Refrigeration Heat Exchanger					
WL-PT4	Glycol Storage Tank					
WL-PT5	Glycol Pumps					
WL-PT6	Crystallizer Pumps					
WL-PT7	Centrifuge					

COMPANY	EQUIPMENT LIST	P.N.
LOCATION	PEDCo-ENVIRONMENTAL Cincinnati, Ohio	CHECKED BY ____ DATE ____
Sodium Solution Regenerable		COMPUTED BY ____ DATE ____

Table U-1. (Cont.) EQUIPMENT LIST FOR THE SODIUM SOLUTION REGENERABLE SYSTEM

ITEM NO.	DESCRIPTION	NO. OF ITEMS	H.P/ ITEM	TOTAL H.P.	COST/ ITEM	TOTAL COST
WL-PT8	Centrate Tank					
WL-PT9	Dryer					
WL-PT10	Elevator					
WL-PT11	Na_2SO_4 Storage Tank					
WL-PT12	Na_2SO_4 Feeder					
WL-PT13	Water Make-up Pump					
	Regeneration System					
WL-R1	Evaporators					
WL-R2	Evaporator Feed Preheater					
WL-R3	Evaporator Feed Pump					
WL-R4	Primary Condenser					
WL-R5	Condensate Receiver Tank					
WL-R6	Condensate Pump					
WL-R7	SO_2 Stripper					
WL-R8	Stripper Tank					
WL-R9	SO_2 Blower					
WL-R10	Dissolving Tank					
WL-R11	Dissolving Tank Agitator					
WL-R12	Dissolving Tank Pump					
	Particulate Removal					
WL-PR1	Venturi					
WL-PR2	Venturi Agitator					
WL-PR3	Venutri Circulation Pump					
WL-PR4	Venturi Circulation Tank					

Table U-2. VARIABLE DESIGN PARAMETERS FOR SODIUM SOLUTION REGENERABLE SYSTEMS

Plant	Boiler No.	Flue gas temp., °F	Inlet SO_2 conc., lb/MM Btu	Outlet SO_2 conc., lb/MM Btu
Arthur Kill	20	300	2.38	0.40
	30	293	2.38	0.40
Astoria	10	300	2.38	0.40
	20	300	2.38	0.40
	30	300	2.38	0.40
	40	300	2.38	0.40
	50	300	2.38	0.40
E.F. Barrett	10	281	2.38	0.40
Bergen	1	269	2.38	0.30
	2	269	2.38	0.30
Cromby	2	240	4.29	1.80
Hudson	1	291	3.04	0.30
Lovett	3	310	2.38	0.40
	4	300	2.38	0.40
	5	288	2.38	0.40
Ravenswood	30	700	2.38	0.40
Ridgeland	1	385	7.24	1.80
	2	385	7.24	1.80
	3	385	7.24	1.80
	4	385	7.24	1.80
	5	334	7.24	1.80
	6	334	7.24	1.80

Scrubbing System (Each Train)

Fan: double inlet centrifugal type (1-100% unit)

ΔP: 16.0" H2O

Absorber: sieve tray type with two stages

ΔP: 8.0" H_2O

L/G: 3 gpm/MAcfm/stage (inlet gas to absorber scrubber)

Slurry concentration: 25% (wt.)

SO_2 removal: see Table U-3

Gas velocity: 8 fps

Table U-3. SO_2 REMOVAL EFFICIENCY FOR SODIUM SOLUTION REGENERABLE SYSTEMS

Plant	SO_2 removal efficiency, %
Arthur Kill	83.2
Astoria	83.2
E.F. Barrett	83.2
Bergen	87.4
Cromby	58.0
Hudson	90.1
Lovett	83.2
Ravenswood	83.2
Ridgeland	75.2

Solution storage tanks: 24-hour storage

Pumps: two/stage plus one spare pump for every unit

Table U-4. SIZES OF TURBULENT CONTACT ABSORBERS FOR THE SODIUM SOLUTION REGENERABLE PROCESS

Plant	No. of absorbers	Dimensions (h x w x l), ft
Arthur Kill	8	45 x 15 x 40
Astoria	16	45 x 15 x 37
E.F. Barrett	1	45 x 15 x 60
Bergen	5	45 x 15 x 42
Cromby	2	45 x 15 x 35
Hudson	4	45 x 15 x 35
Lovett	5	45 x 15 x 39
Ravenswood	8	45 x 15 x 40
Ridgeland	4 2	45 x 15 x 37 45 x 15 x 56

Entrainment separator: Chevron vane type (two/absorber)

Number passes: two

ΔP: 2.0" H_2O

Gas velocity: 7 fps

Purge treatment:

Refrigeration: temperature = 40°F; flow = 5% of recirculation rate

Centrifuge: solids = 5% of stoichiometric Na_2CO_3

Acid Plant: 125% of average SO_2 flow

SO_2 regeneration:

Evaporators: 30% slurry of $NaHSO_3$ based on SO_2 absorbed. Evaporators are sized for 1 hour retention and 50% free space.

Reboilers: 7.5°F temperature rise; 8 lb of steam per lb of SO_2

Stripper: overhead is 1 lb SO_2 and 1 lb H_2O for every 1 lb SO_2

Reheater: indirect tubular type

ΔT: 50°F (inlet temperature = 125°F;
outlet temperature = 175°F)

Heating medium: low-pressure steam

B. DESIGN RATIONALE

- The soda ash storage silo is sized for 30 days storage to allow the plant to continue operating in the event of an interruption in the supply of soda ash.
- The feeders are sized at 3.0 times the maximum soda ash flow.
- The soda ash slurry storage is sized for 4 hours storage.

- All critical pumps in the process are provided with spares.

- A sieve tray unit selected for removal of the bulk of the SO_2 has 2 stages of sieve trays to provide the contact area necessary for mass transfer to SO_2 from the gas to the liquid phase. The absorber is designed for an L/G of 3 GPM/MACFM/stage (inlet gas to the absorber) and a pressure drop of 8 in. H_2O. Slurry concentration will be 25%; gas velocity in the unit will be 8 FPS; and SO_2 removal is specified to be about 90%. Standard sizes for absorbers and venturis for the sodium solution regenerable process are showning Tables U-5 and U-6, respectively. Standard scrubber modules are presented in Figures U-2a through U-2d.

- The absorbers have common solution storage tanks sized to provide 24-hour storage of the slurry. This storage time allows the absorbers to operate for approximately 24 hours in the event the acid plant should breakdown.

- A Chevron vane-type entrainment separator removes mist thatis carried over in the gas from the absorber. This unit contains two stages of Chevron vanes, which are washed continuously with water. Superficial gas velocity through the unit is 7 FPS and the pressure drop is expected to be about 2 in. H_2O.

- The gas leaving the entrainment separator must be reheated to desaturate it and provide buoyancy for adequate atmospheric dispersion. The number of degrees of reheat necessary is variable and dependent on a number of factors such as stack height, local weather conditions, population density, terrain, and maximum allowable SO_2 ground-level concentration. For this study, a reheat ΔT of 50°F is used; this value is believed to be about the minimum acceptable. Obviously, the lowest acceptable reheat ΔT should be chosen, since each increase of 50°F of the flue gas temperature requires about 1.5% of the gross heat input to the plant.

Table U-5. TABLE OF ABSORBER STANDARD SIZES FOR THE SODIUM SOLUTION REGENERABLE PROCESS

Description	I	II	III	IV	V
Flow rate @125°F, acfm	300,000	250,000	150,000	100,000	50,000
Flow rate @300°F, acfm	398,000	325,000	195,000	130,000	60,000
Nominal MW	150	110	65	45	20
Absorber					
Length (A), ft	39.0	28.0	17.0	11.0	6.0
Width (B), ft	15.0	15.0	15.0	15.0	15.0
Height (C), ft	45.0	45.0	45.0	45.0	45.0
Absorber tank					
Diameter (D), ft	44.0	37.0	29.0	23.5	17.0
Height (E), ft	20.0	20.0	20.0	20.0	20.0
Entrainment Separator					
Height (F), ft	15.0	15.0	15.0	15.0	15.0
Hot duct					
Dimension (G), ft	12 x 11	10 x 9	7 x 8	6 x 6	4 x 5
Reheater to Separator					
Overall dimensions (H), ft	30.0	25.0	20.0	20.0	20.0
Stack duct					
Dimensions (J), ft	14 x 13	12 x 10	10 x 8	7 x 7	5 x 5

Table U-6. TABLE OF VENTURI STANDARD SIZES FOR THE SODIUM SOLUTION REGENERABLE PROCESS

Description	I	II	III	IV	V
Flow rate @ 125°, acfm	300,000	250,000	150,000	100,000	50,000
Flow rate @ 300°, acfm	390,000	325,000	195,000	130,000	65,000
Nominal MW	150	110	65	45	20
Venturi					
Length (K), ft	29.0	22.5	15.0	10.0	5.6
Width (L), ft	6.5	6.0	5.5	5.5	5.0
Height (M), ft	20.0	20.0	20.0	20.0	20.0
Venturi tank					
Diameter (N), ft	15.5	13.0	10.0	8.25	6.0
Height (O), ft	15.0	15.0	15.0	15.0	15.0

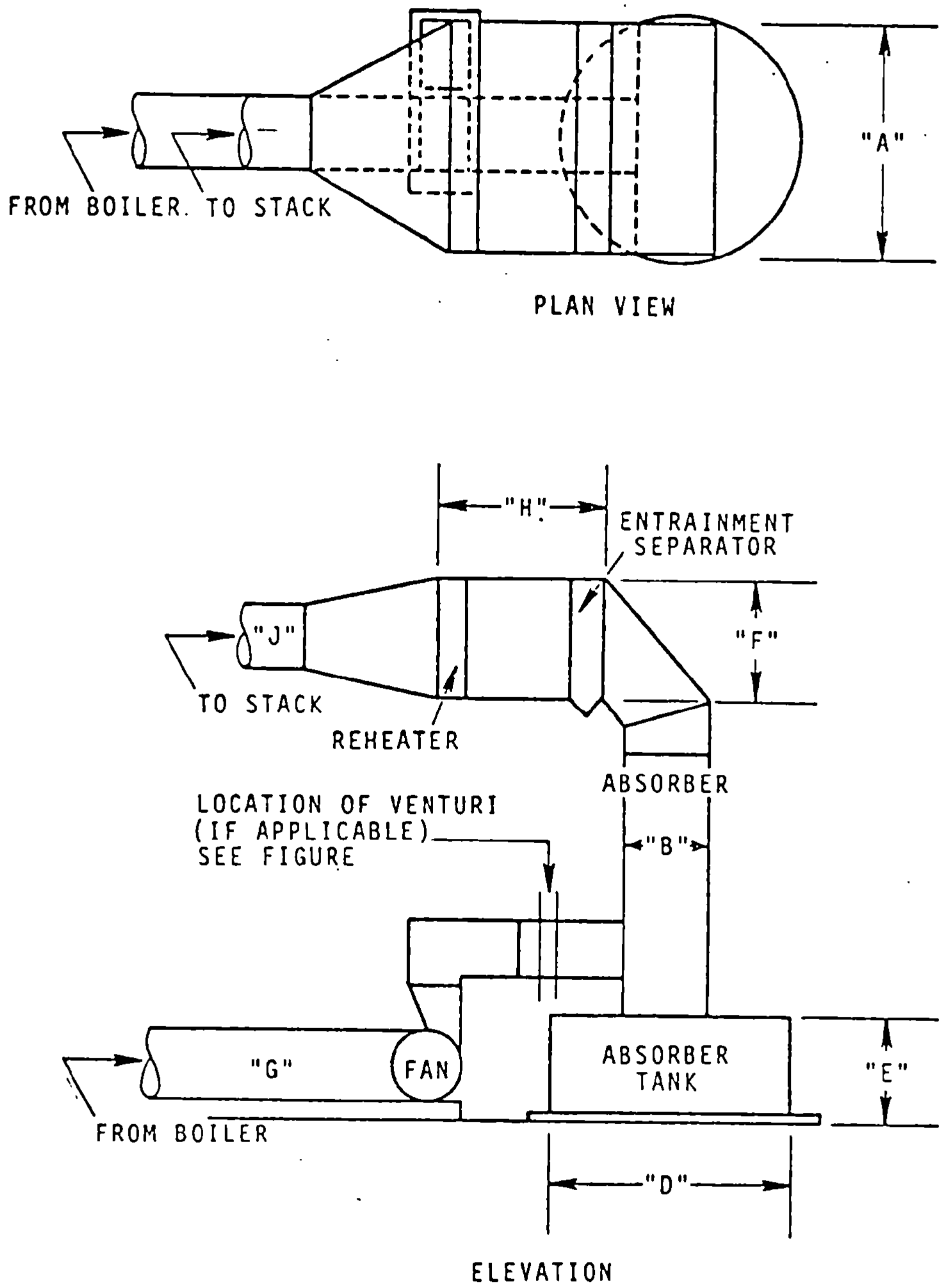


Figure U-2a. Plan view and elevation of an absorber.

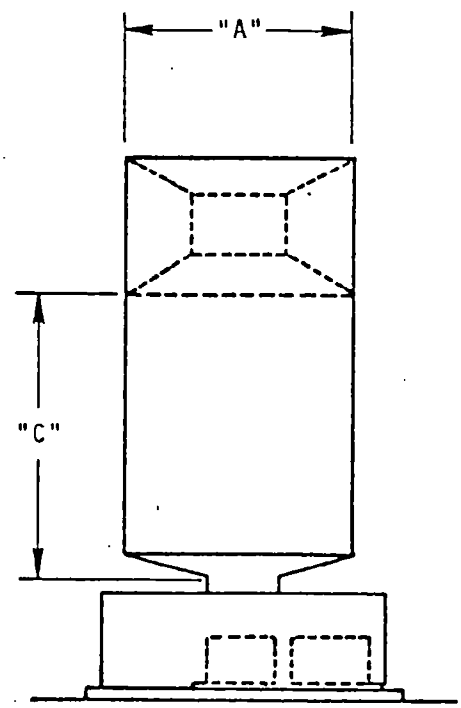
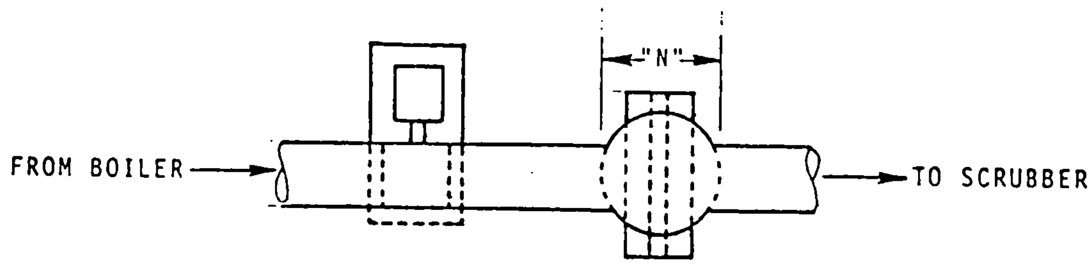
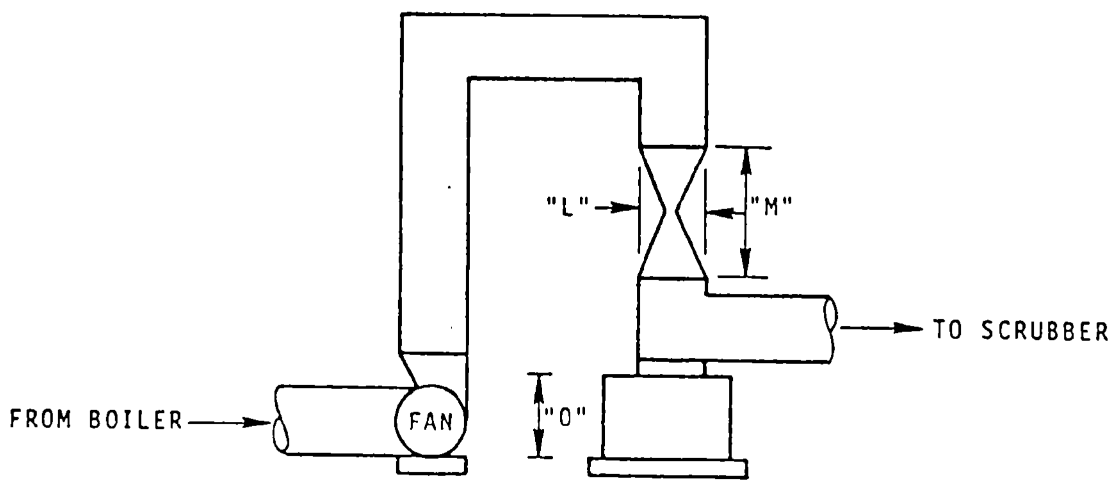


Figure U-2b. Side view of an absorber.



PLAN VIEW



ELEVATION

Figure U-2c. Plan view and elevation of a venturi scrubber.

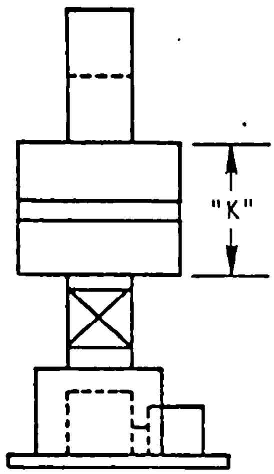


Figure U-2d. Side view of a venturi scrubber.

In the indirect finned tubular heat exchanger selected for the reheater, the first 33% of the rows of tubes are constructed of Alloy 20 for corrosion resistance to the gas, which enters at its dew point. The remaining 67% of the rows are constructed of carbon steel. Heating medium for the unit is low-pressure saturated steam. Pressure drop through the reheater is calculated to be about 4.0" H_2O.

- Based on experience at Will County, a retractable B&W type soot blower is used for each 25 ft^2 of scrubber exit duct cross-section for the heat exchanger. Half of the soot blowers are on the entry side, the remainder on the exit side of the heat exchanger.

- Cost of reheat is based purely on an oil conversion cost in Btu's.

- Purge treatment equipment is based mostly on TVA cost estimates.

- The acid plant costs are based on data furnished by Wellman-Lord.

APPENDIX V

BASIS OF LIMESTONE PROCESS DESIGN

APPENDIX V

BASIS OF LIMESTONE PROCESS DESIGN

A. DESIGN VALUES

The process design basis for the wet limestone system used in this study was determined after review of process design used or proposed for use at various installations and discussions with control system manufacturers. A flowsheet of the limestone system is shown in Figure V-1. Table V-1 presents a complete list of equipment required for the limestone process. Typical installation times for the various stages of the limestone process are presented in Figure V-2, the Critical Path Schedule.

Values of the major design parameters are tabulated below:

- Variable design parameters: Table V-2.
- Constant design parameters: Tables V-3 and V-4.
- Flue gas pressure: atmospheric
- Reheat: 50°F above dew point (from 125 to 175°F)
- Limestone consumption: 130% stoichiometric

<u>Limestone System</u>

Size: (unloading hoppers for the twenty plants): 200 tons

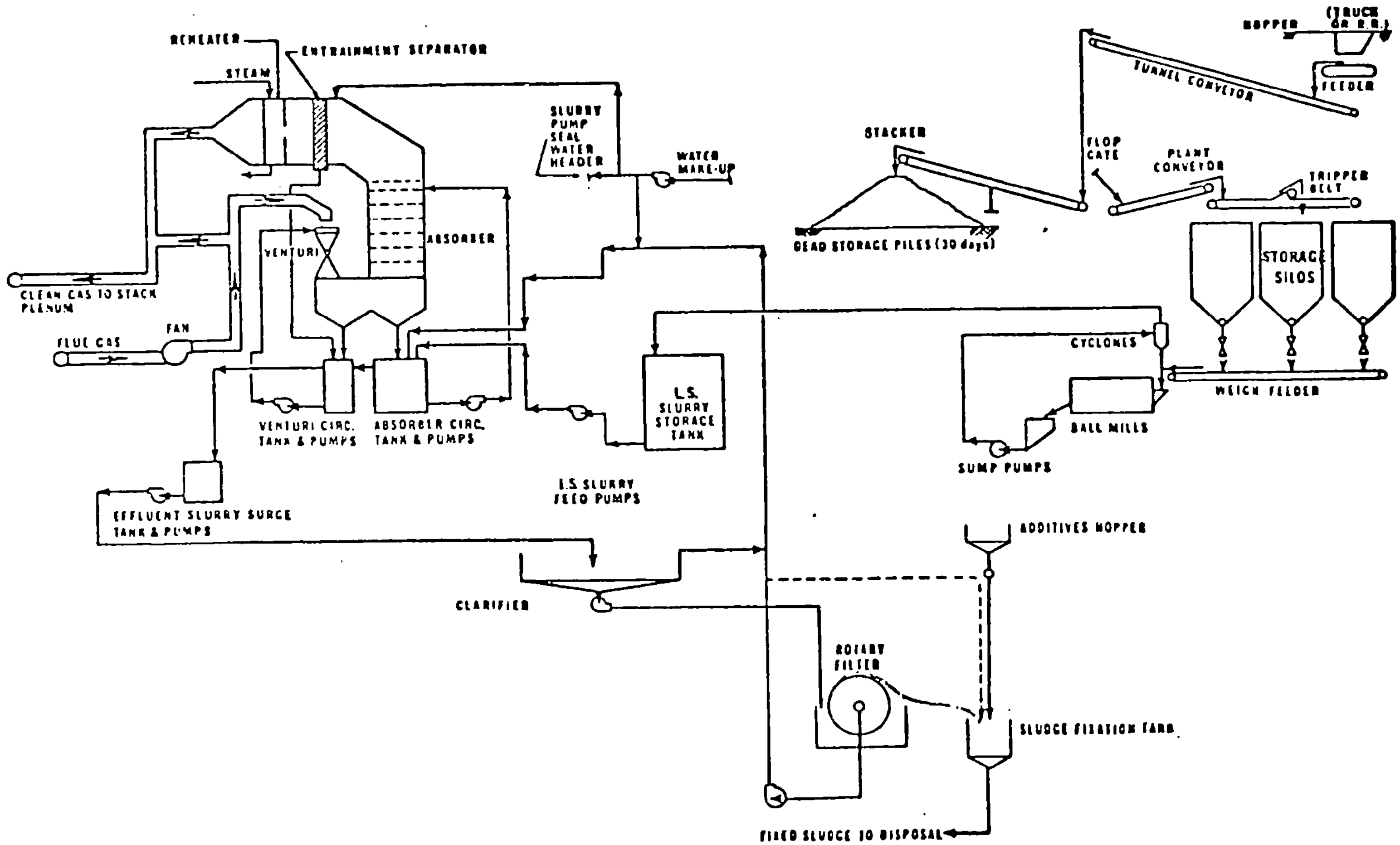


Figure V-1. Limestone scrubbing system.

COMPANY	_______________
LOCATION	_______________
	_______________

Table V-1.
EQUIPMENT LIST

PEDCo-ENVIRONMENTAL
Cincinnati, Ohio

P.N. _______________
CHECKED BY _______________ DATE _______
COMPUTED BY _______________ DATE _______

ITEM NO.	DESCRIPTION	NO. OF ITEMS	H.P/ ITEM	TOTAL H.P.	COST/ ITEM	TOTAL COST
	Limestone Handling System					
LL-L1	Hopper					
LL-L2	Unloading Feeder					
LL-L3	Tunnel Conveyor					
LL-L4	Flop Gate					
LL-L5	Stacker					
LL-L6	Plant Conveyor					
LL-L7	Tripper Belt					
LL-L8	Storage Silos					
LL-L9	Vibrating Feeders					
LL-L10	Weigh Feeders					
LL-L11	Dust Collector					
LL-L12	Ball Mills					
LL-L13	Ball Mill Tanks					
LL-L14	Ball Mill Tank Sump Pump					
LL-L15	Limestone Classifier					
LL-S1	Slurry Storage Tank					
LL-S2	Slurry Mixer					
LL-S3	Slurry Pumps					
LL-S4	Slurry Surge Tank					
LL-S5	Surge Pump					
	SO_2 Scrubbing System					
LL-A1	Absorber					
LL-A2	Absorber Tank					
LL-A3	Absorber Agitator					
LL-A4	Absorber Circulation Pump					
	Sludge System					
LL-C1	Clarifier Tank					
LL-C2	Overflow Pump					

Table V-1 (Continued).
EQUIPMENT LIST

PEDCo-ENVIRONMENTAL
Cincinnati, Ohio

COMPANY ____________

LOCATION ____________

____

P.N. ____________

CHECKED BY ____________ DATE ______

COMPUTED BY ____________ DATE ______

ITEM NO.	DESCRIPTION	NO. OF ITEMS	H.P/ ITEM	TOTAL H.P.	COST/ ITEM	TOTAL COST
LL-C3	Underflow Pump					
LL-C4	Vacuum Filter					
LL-C5	Vacuum Pump					
LL-C6	Return Filtrate Pump					
LL-C7	Mix Tank					
LL-C8	Mixer					
LL-C9	Sludge Pump					
LL-C10	Additive Hopper					
LL-C11	Water Make-Up Pump					
LL-SR1	Mobile Equipment					
	Heat Exchanger System					
LL-H1	Heat Exchanger					
LL-H2	Soot Blowers					
	Air Piping System					
LL-AP1	Induced Draft Fans					
LL-AP2	Ducting					
LL-AP3	Butterfly Valves w/Operator					
	Particulate Removal System					
LL-V1	Venturi System					
LL-V2	Venturi Circulation Tank					
LL-V3	Venturi Circulation Tank					

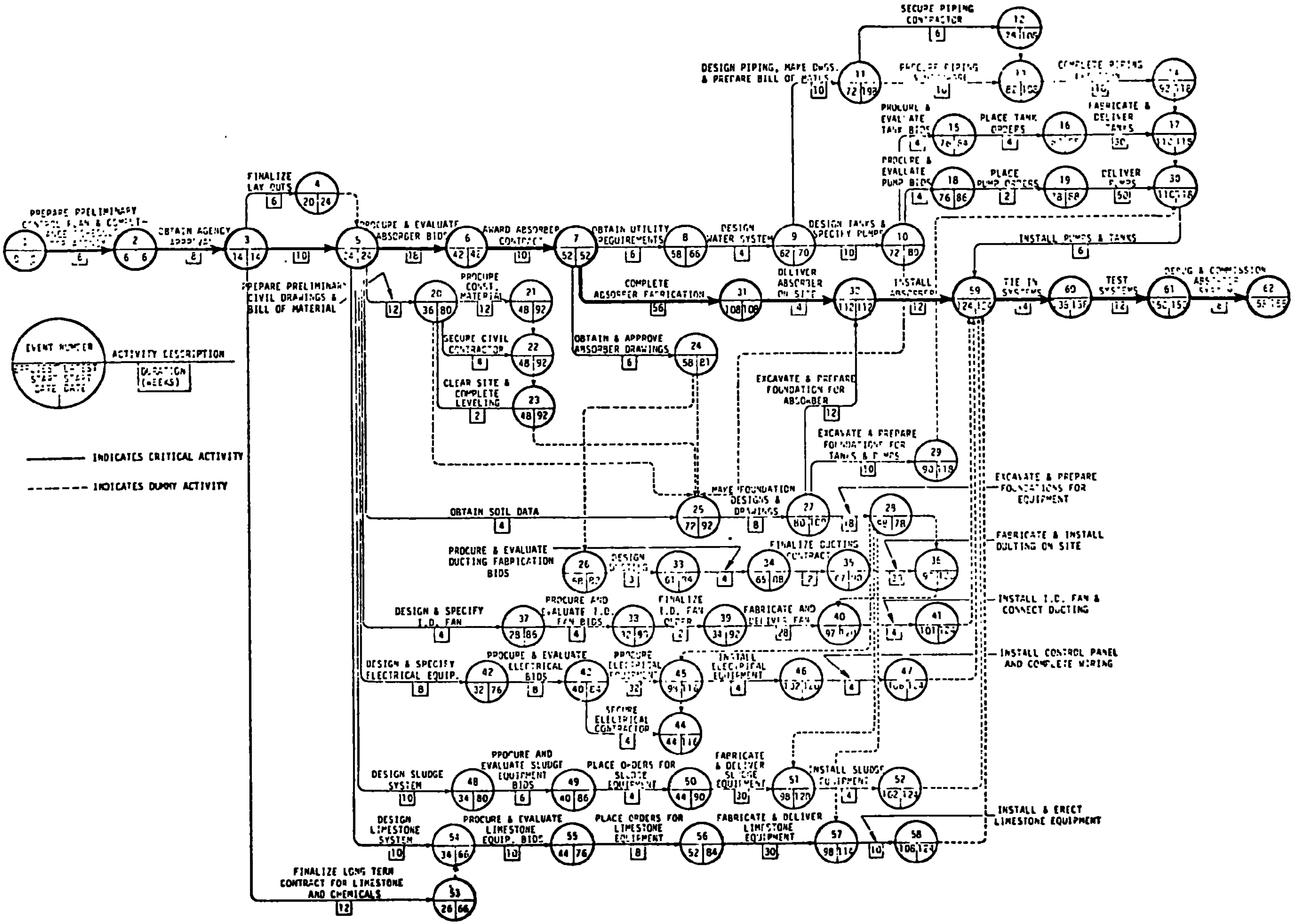


Figure V-2. Critical path schedule.

Table V-2. VARIABLE DESIGN PARAMETERS FOR LIMESTONE SYSTEMS

Plant	Boiler No.	Flue gas temp.,°F	Inlet SO_2 conc., lb/MM Btu	Outlet SO_2 conc., lb/MM Btu
Arthur Kill	20	300	2.38	0.40
	30	293	2.38	0.40
Astoria	10	300	2.38	0.40
	20	300	2.38	0.40
	30	300	2.38	0.40
	40	300	2.38	0.40
	50	300	2.38	0.40
E.F. Barrett	10	281	2.38	0.40
Bergen	1	269	2.38	0.30
	2	269	2.38	0.30
Cromby	2	240	4.29	1.80
Hudson	1	291	3.04	0.30
Lovett	3	310	2.38	0.40
	4	300	2.38	0.40
	5	288	2.38	0.40
Ravenswood	30	700	2.38	0.40
Ridgeland	1	385	7.24	1.80
	2	385	7.24	1.80
	3	385	7.24	1.80
	4	385	7.24	1.80
	5	334	7.24	1.80
	6	334	7.24	1.80

Feeders, Conveyors: capacity = 5.8 x maximum limestone flow

Lime storage silos: 3 days storage

Limestone slurry storage tank: 24 hours storage

Limestone slurry feed pumps: two pumps/train with one spare for each two operating pumps

Raw water pumps: two

Clarifier and sludge pond dimension: see Table V-3

Clarifiers: two per plant

Table V-3. CLARIFIER AND SLUDGE POND DIMENSIONS FOR LIMESTONE SYSTEMS

Plant	Clarifier, ft		Sludge pond, acre-ft/yr
	Diameter	Height	
Arthur Kill	75	20	44
Astoria	100	20	73
E.F. Barrett	49	20	26
Bergen	65	20	64
Cromby	60	20	45
Hudson	56	20	49
Lovett	49	20	17
Ravenswood	75	20	43
Ridgeland	165	20	115

Scrubbing System (each train)

Fan: double inlet centrifugal (1-100% unit)

ΔP: 24.0" H_2O

Absorber: TCA type with two beds

L/G: 65 gpm/MAcfm (inlet gas to absorber scrubber)

Slurry concentration: 8% (wt.)

SO_2 removal: see Table V-4

Table V-4. SO_2 REMOVAL EFFICIENCY FOR THE LIMESTONE SYSTEMS

Plant	SO_2 removal, %
Arthur Kill	83.2
Astoria	83.2
E.F. Barrett	83.2
Bergen	87.4
Cromby	58.0
Hudson	90.1
Lovett	83.2
Ravenswood	83.2
Ridgeland	75.2

Gas velocity: 10 fps, absorber

Circulating tank: 10 minutes retention, absorber

Pumps: four/train plus one spare pump for each train, absorber

Entrainment separator: Chevron vane type

Number passes: two

ΔP: 2.0" H_2O

Gas velocity: 7 fps

Reheater: indirect tubular type

ΔT: 50°F (inlet temperature + 125°F; outlet temperature = 175°F)

Heating medium: low pressure steam

B. DESIGN RATIONALE

- The unloading hoppers are sized to hold 200 tons to accomodate unloading of trains as well as trucks.
- The live storage silo is sized for 3 days storage.
- The feeders and conveyors are sized at 5.8 times the maximum limestone flow to allow the unloading of limestone during a 40-hour week while the plant operates continuously.
- The limestone slurry storage tank is sized for 24 hours storage to allow the scrubbing trains to continue operating this limestone for 24 hours if supply is interrupted.
- All critical pumps in the process are provided with spares.
- The thickeners and new pond are used with diking to provide sufficient pond space for the life of the plant. The thickener concentrates the effluent slurry from 15% solids to 30% solids and then discharges the 30% effluent slurry to the vacuum filtration units. The effluent leaves the filtration unit with a slurry 60% by weight and then enters a mixing tank where the fixation additives are stirred in with the 60% slurry, which is then pumped to the sludge pond. Figure V-3 illustrates how sludge pond dimensions are calculated.

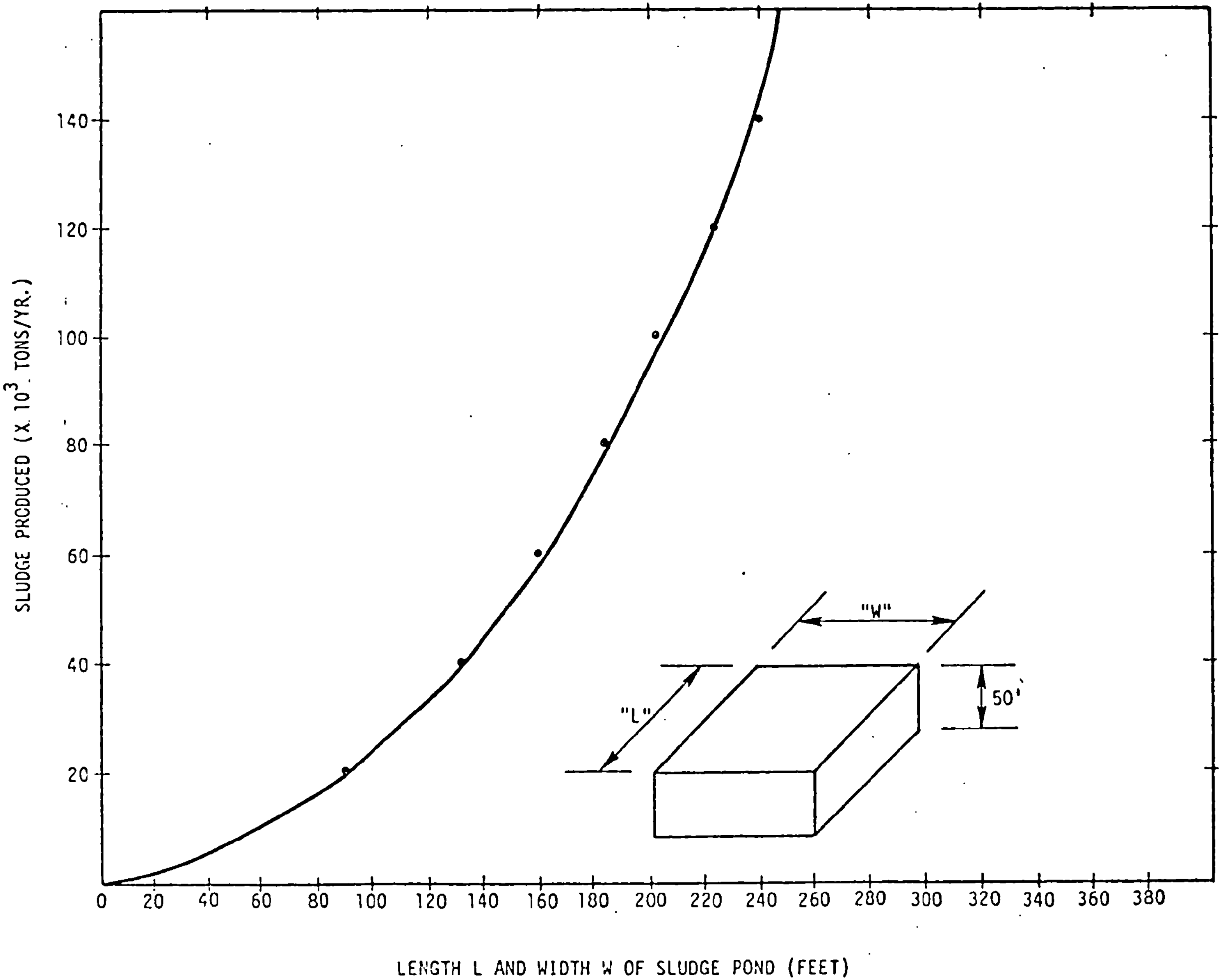


Figure V-3. Sludge pond size sheet.

- A UOP* Turbulent Contact Absorber (TCA) was selected for removal of the bulk of the SO_2. This unit has two beds of hollow plastic spheres, which move randomly between support grids and provide the contact area necessary for mass transfer of SO_2 from the gas to the liquid phase. The absorber is designed for an L/G of 65 gpm/MAcfm (inlet gas to the absorber) and a pressure drop of 7 in. H_2O. Slurry concentration will be 8%; gas velocity in the unit will be 10 fps; and SO_2 removal is specified to be about 85% plus. The size of the turbulent contact absorbers is shown in Table V-5. Standard sizes for absorbers and venturis for the limestone process are shown in Tables V-6 and V-7, respectively. Standard scrubber modules are presented in Figures V-4a through V-4d.

- Each absorber has a circulating tank sized to provide a 10-minute retention time based on the slurry circulation rate. This retention time is essentially the same as that reported by others and should provide sufficient time for desupersaturation and thus reduce scaling potential. If long retention time are required, the incremental cost would be small since the circulating tanks do not represent large cost items; space limitations may require locating a secondary tank some distance away and providing additonal piping.

- The Chevron vane-type entrainment separator is incorporated to remove mist carried over in the gas from the absorber. This unit contains two stages of Chevron vanes, which are washed continuously with water. Superficial gas velocity through the unit is 7 fps and the pressure drop is expected to be about 2.0" H_2O. Design of the unit is based on information from C-E, Chemico, and UOP.

- The gas leaving the entrainment separator must be reheated to desaturate it and provide buoyancy for adequate atmospheric dispersion. The number of degrees of reheat necessary is variable and dependent on a number of factors such as stack height, local weather conditions, population density, terrain, and maximum allowable SO_2 ground level concentration. For this study, a

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* Universal Oil Products Company (Air Correlation Division).

Table V-5. SIZES OF TURBULENT CONTACT ABSORBERS FOR THE LIMESTONE SYSTEMS

Plant	No. of absorbers	Dimensions (h x w x l), ft
Arthur Kill	8	45 x 15 x 32
Astoria	16	45 x 15 x 30
E.F. Barrett	1	45 x 15 x 45
Bergen	5	45 x 15 x 31
Cromby	2	45 x 15 x 28
Hudson	4	45 x 15 x 35
Lovett	5	45 x 15 x 29
Ravenswood	8	45 x 15 x 30
Ridgeland	4 2	45 x 15 x 30 45 x 15 x 45

Table V-6. TABLE OF ABSORBER STANDARD SIZES FOR THE LIMESTONE PROCESS

Description	I	II	III	IV	V
Flow rate @125°F, acfm	300,000	250,000	150,000	100,000	50,000
Flow rate @300°F, acfm	455,000	325,000	195,000	130,000	65,000
Nominal MW	150	110	65	45	20
Absorber					
Length (A), ft	39.0	28.0	17.0	11.0	6.0
Width (B), ft	15.0	15.0	15.0	15.0	15.0
Height (C), ft	45.0	45.0	45.0	45.0	45.0
Absorber tank					
Diameter (D), ft	44.0	37.0	29.0	23.5	17.0
Height (E), ft	20.0	20.0	20.0	20.0	20.0
Entrainment Separator					
Height (F), ft	15.0	15.0	15.0	15.0	15.0
Hot duct					
Dimension (G), ft	12 x 11	10 x 9	7 x 8	6 x 6	4 x 5
Reheater to Separator					
Overall dimensions (H), ft	30.0	25.0	20.0	20.0	20.0
Stack duct					
Dimensions (J), ft	14 x 13	12 x 10	10 x 8	7 x 7	5 x 5

Table V-7. TABLE OF VENTURI STANDARD SIZES FOR THE LIMESTONE PROCESS

Description	I	II	III	IV	V
Flow rate @125°F, acfm	350,000	250,000	150,000	100,000	50,000
Flow rate @300°F, acfm	455,000	325,000	195,000	130,000	65,000
Nominal MW	150	110	65	45	20
Venturi					
Length (K), ft	29.0	22.5	15.0	10.0	5.6
Width (L), ft	6.5	6.0	5.5	5.5	5.0
Height (M), ft	20.0	20.0	20.0	20.0	20.0
Venturi tank					
Diameter (N), ft	15.5	13.0	10.0	8.25	6.0
Height (O), ft	15.0	15.0	15.0	15.0	15.0

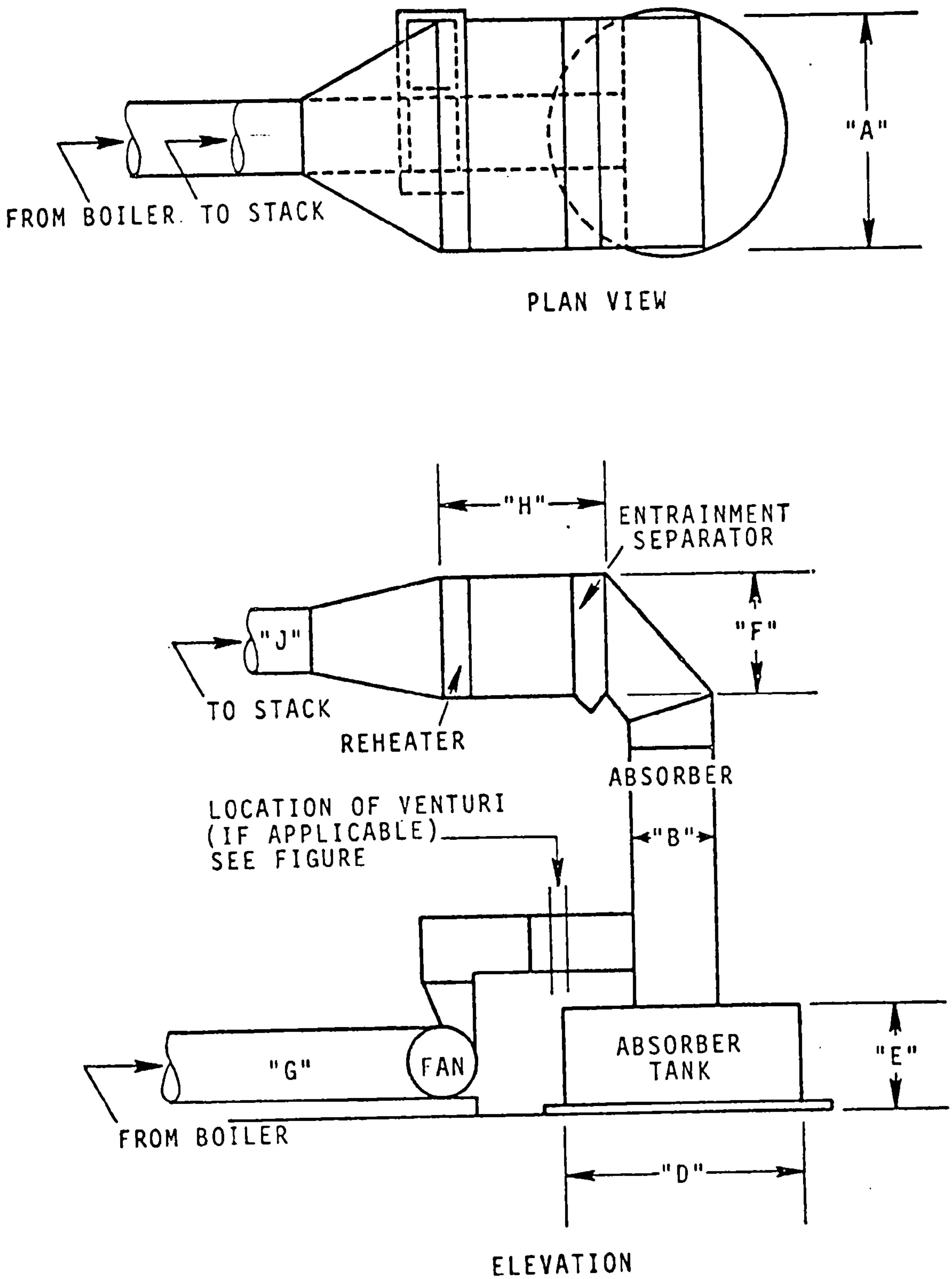
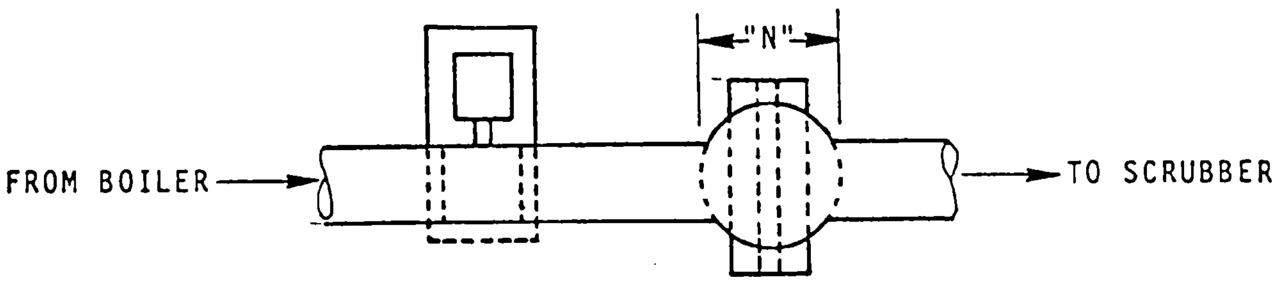
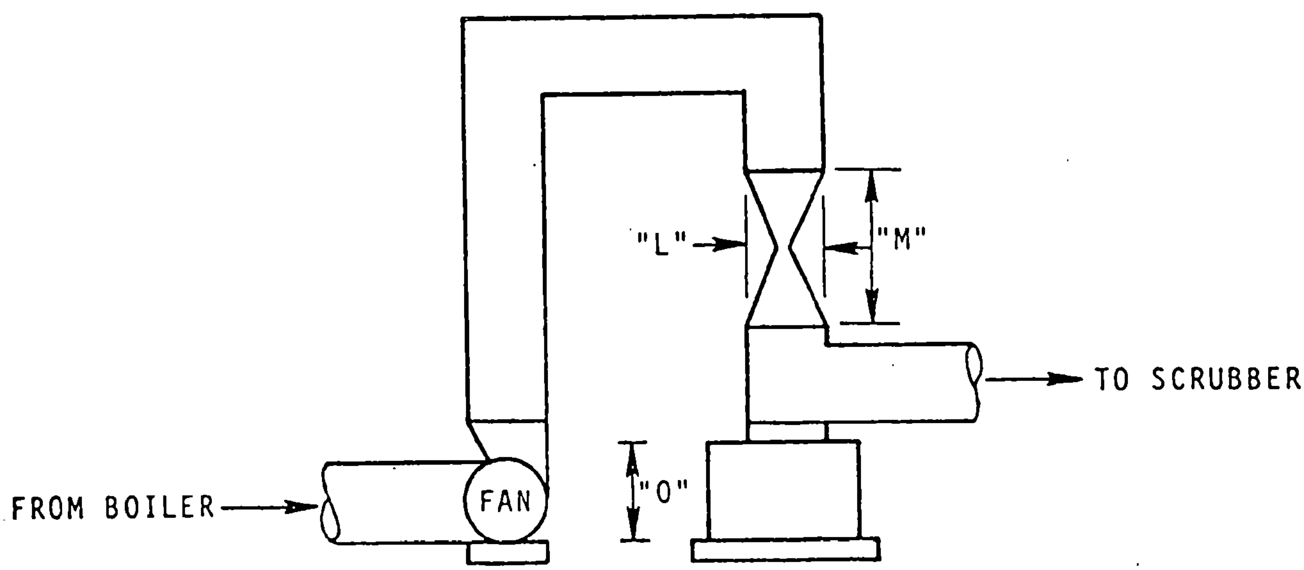


Figure V-4a. Plan view and elevation of an absorber.

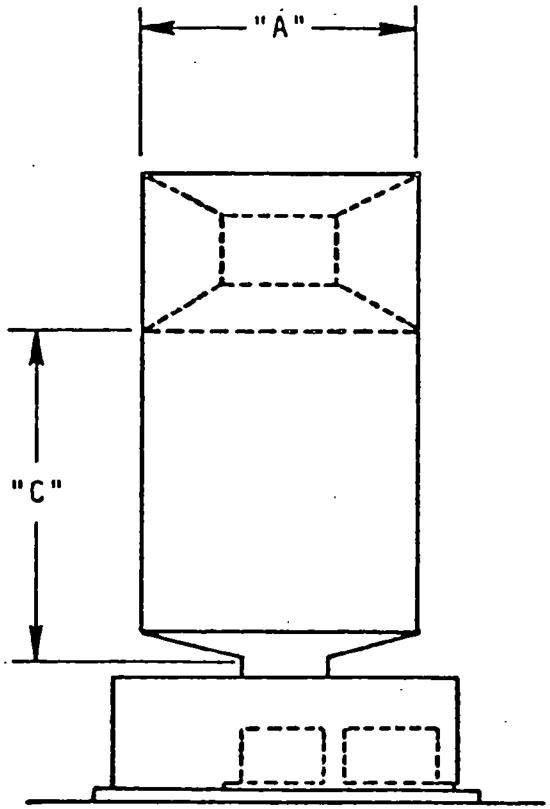


PLAN VIEW



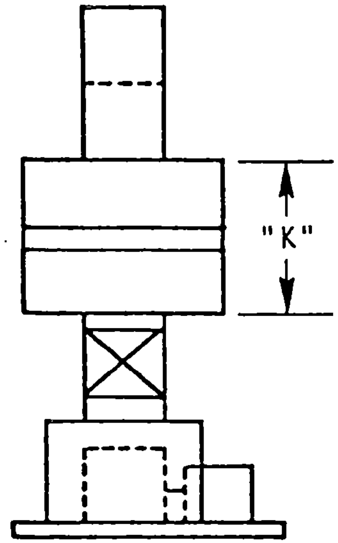
ELEVATION

Figure V-4b. Plan view and elevation of a venturi scrubber.



SIDE VIEW

Figure V-4c. Side view of an absorber.



SIDE VIEW

Figure V-4d. Side view of a venturi scrubber.

reheat ΔT of 50°F is used; this value is believed to be about the minimum acceptable. Obviously, the lowest acceptable reheat ΔT should be chosen, since each increase of 50°F of the flue gas temperature requires about 1.5% of the gross heat input to the plant.

In the indirect finned tubular heat exchanger selected for the reheater, the first 33% of the rows of tubes are constructed of Alloy 20 for corrosion resistance to the gas, which enters at its dew point. The remaining 67% of the rows are constructed of carbon steel. Heating medium for the unit is low-pressure saturated steam. Pressure drop through the reheater is calculated to be about 4.0" H_2O.

- Based on experience at Will County, a retractable B&W type soot blower is used for each 25 ft^2 of scrubber exit duct cross-section for the heat exchanger. Half of the soot blowers are on the entry side, the remainder on the exit side of the heat exchanger.
- Cost of reheat is based purely on an oil conversion cost in Btu's.

APPENDIX W

ESP SUPPORT INFORMATION

APPENDIX W

ESP SUPPORT INFORMATION

The design basis for the cost and installation of ESP's was determined after review of process designs now in use or proposed, and discussions with control system manufacturers. A list of equipment required for installation of an ESP is presented in Table W-1. The critical path schedule, Figure W-1, illustrates the time required for installation of various stages of an ESP. Standard layouts for an ESP are shown in Figure W-2.

Table W-1

EQUIPMENT LIST

PEDCo-ENVIRONMENTAL
Cincinnati, Ohio

COMPANY ____________________

LOCATION Electrostatic Precipitator

P.N. ____________________

CHECKED BY ____________ DATE ______

COMPUTED BY ____________ DATE ______

ITEM NO.	DESCRIPTION	NO. OF ITEMS	H.P/ ITEM	TOTAL H.P.	COST/ ITEM	TOTAL COST
	ESP					
	ESP and Vaning					
	Transformer and Rectifier Sets					
	Rappers (wires and plates)					
	ASH HANDLING SYSTEM					
	Ash Hoppers					
	Fly Ash Pipe and Fittings					
	Fly Ash Valves					
	Segregating Valves					
	Ash Silo					
	Primary Collector					
	Secondary Collector					
	Vent Filter					
	Dustless Unloader					
	Exhauster					
	Vacuum Breaker					
	TRANSITION DUCTING					
	Ducting					
	Valves					

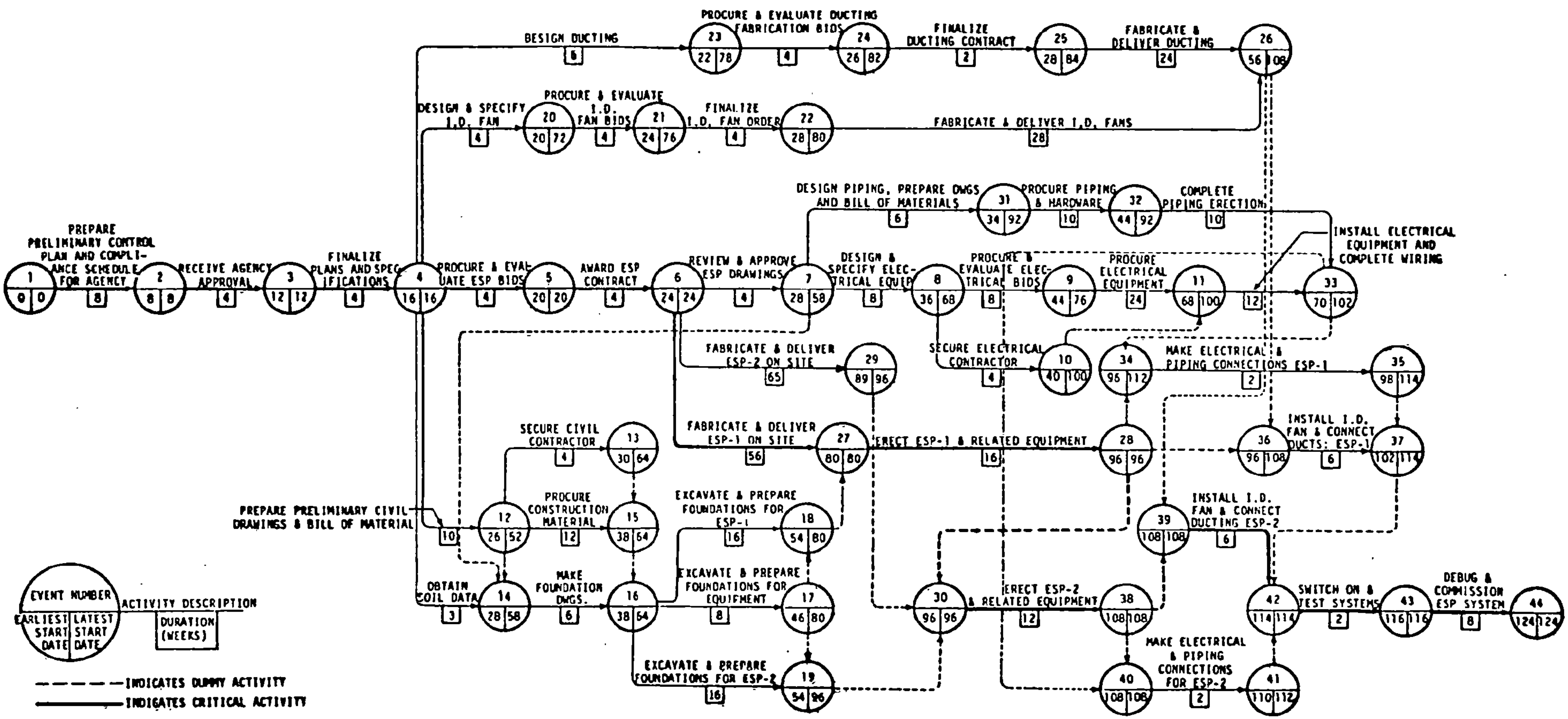


Figure W-1. ESP Critical Path Schedule.

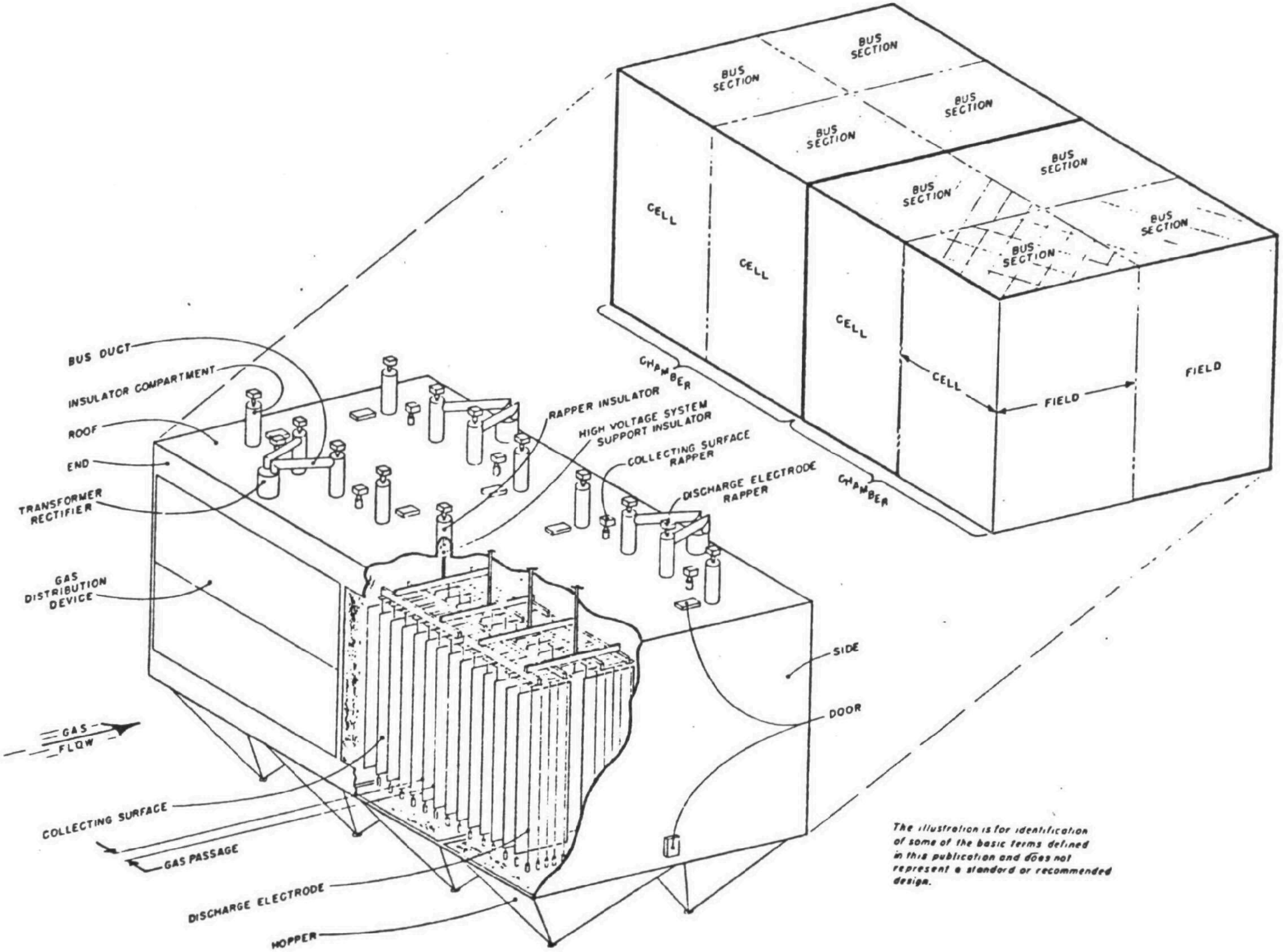


Figure W-2. ESP standard layout.

APPENDIX X

COMPANY LETTERS TO THE FEDERAL ENERGY ADMINISTRATION

APPENDIX X-1 ARTHUR KILL POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Consolidated Edison Company:

"The questions (on the FEA information request) were answered on the basis that any order to convert to coal firing would be on a non-emergency basis, and would be for the long term. No allowance or consideration was made for an AQCS further than adequate precipitators. The cost figures used are estimates and should be used as order of magnitude numbers."

Original Coal specifications for Boilers 20 and 30 are shown below:

	Boiler 20	Boiler 30
HHV, Btu/lb	13,600	13,600
Ash, %	7.2	7.2
Volatite, %	36.5	36.5
Ash fusion temp.,°F	1900-2300	2100
Moisture, %	3.4	3.4
Free carbon, %	52.9	52.9
Grindability	63	63

The anticipated acquistion or refurbishing of coal handling and firing equipment that would be required to reinstitute coal burning capability, and information relevant to the adequacy of storage facilities for coal are listed below. Costs and outage time are also provided.

Item	Estimated cost, $	Estimated lead time & construction time, yr	Estimated plant out time, wk
Arthur Kill Unit 20			
1) Install new precipitators	6,000,000	2 - 2 1/2	2-3
2) Install new bottom ash system	750,000	1 - 1 1/2	2
3) Install new fly ash system & storage facility	1,500,000	2 - 2 1/2	None
4) Overhaul raw coal system	300,000	1/6 - 1/2	None
5) Overhaul pulverizer system	100,000	1/2 - 1	None
6) Overhaul burner equipment	100,000	1/2 - 1	2
7) Check controls & checkout system	25,000	1/2	2
Arthur Kill Unit 30			
1) Install new precipitators	7,000,000	2 - 2 1/2	1/2 - 1 yr
2) Convert bottom to coal firing	75,000	2 Wks	2
3) Install new fly ash system	Incl. in Un.20	2 - 2 1/2	None
4) Overhaul raw coal system	Incl. in Un.20	1/6 - 1/2	None
5) Complete pulverizer overhaul	75,000	3 Wks	None
6) Change boiler orifices to coal firing	20,000	2 Wks	2
7) Change combustion & burner control to coal firing	20,000	3 Wks	2
8) Checkout coal firing system	10,000	1 Wk	1/2

"Coal storage (on ground) available, deliveries by rail only no river edge loading or unloading available.

The differential operation and maintenance cost estimates are as follows:

	Operation	Maintenance	Total
Unit 20	$ 79,557	$ 61,084	$140,641
Unit 30	$441,386	$294,465	$735,851

APPENDIX X-2 ASTORIA POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal energy Administration by the Consolidated Edison Company:

> "The questions (on the FEA information request) were answered on the basis that any order to convert to coal firing would be on a non-emergency basis, and would be for the long term. No allowance or consideration was made for an AQCS further than adequate precipitators. The cost figures used are estimates and should be used as order of magnitude numbers."

Original coal specifications for Boilers 10 and 20, and for Boilers 30, 40, and 50 are shown below:

	Boilers 10-20	Boilers 30-50
HHV, Btu/lb	13,253	13,600
Ash,%	8.0	7.2
Volatile, %	37.8	36.5
Ash fusion temp.,°F	1900-2300	1900-2300
Moisture, %	4.1	3.4
Free carbon, %	50.1	52.9
Grindability	64	63

The anticipated acquisition or refurbishing of coal handling and firing equipment that would be required to reinstitute coal burning capability, and information relevant to the adequacy of storage facilities for coal are listed below. Costs and outage time are also provided.

The differential operation and maintenance cost estimates are as follows:

	Operation	Maintenance	Total
Units 10&20,$	231,578	293,230	524,808
Units 30&40,$	154,334	195,487	349,821
Unit 50,$	231,540	293,947	525,487

	Estimated cost, $	Estimated lead time & construction time, yr	Estimated plant out time, wk
Astoria Units 10 & 20			
1) Install new precipitator	4,000,000	2 - 2 1/2	2 - 3
2) Install new bottom ash system	750,000	1 - 1 1/2	2
3) Restore fly ash system & silo	800,000	1	2
4) Overhaul raw coal system	500,000	1	None
5) Overhaul pulverizer system	150,000	1/2 - 1	None
6) Overhaul burner equipment	100,000	1/2 - 1	2
7) Overhaul/Checkout coal controls	25,000	1/2	2
Unit 30			
1) Install new precipitator	6,000,000	2 - 2 1/2	2 - 3
2) Install new bottom ash system	750,000	1 - 1 1/2	2
3) Restore fly ash system & silo	Incl. in Un. 10&20	1	2
4) Overhaul raw coal system	Incl. in Un. 10&20	1	None
5) Overhaul pulverizer system	150,000	1/2 - 1	None
6) Overhaul burner equipment	60,000	1/2 - 1	4
7) Overhaul/checkout coal controls	50,000	1/2 - 1	2
Unit 40			
1) Install new precipitator	6,000,000	2 - 2 1/2	2 - 3
2) Overhaul bottom ash system	50,000	1/3 - 1/2	2
3) Overhaul fly ash system	Incl. in Un. 10&20	1	2
4) Overhaul raw coal system	Incl. in Un. 10&20	1	None
5) Overhaul pulverizer system	100,000	1/2 - 1	None
6) Overhaul burners	100,000	1/2 - 1	3 - 5
7) Overhaul controls	25,000	1/2	2

Unit 50 - Same as Unit 40

APPENDIX X-3 E. F. BARRETT POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Long Island Lighting Company:

1. Maximum and Minimum Values

These data reflect the range of each fuel characteristic satisfactorily and reliably experienced in operation, although it must be recognized not extremes of each characteristic necessarily simultaneously. The coal and ash handling systems were designed for 13,000 Btu/lb. coal. A decrease in that level (usually as a function of increased ash content) overloads both the coal unloading and coal pulverizing systems reducing boiler capacity and/or reliability. Increased ash content overloads the ash handling systems, decreases precipitator efficiency, produces plume opacity problems and frequently requires load curtailment to empty ash hoppers and associated transport piping. As an additional consideration, ash disposal areas on Long Island are extremely limited in availability. At the Barrett Station resolution of environmental (water) problems must be accomplished before existing areas of limited capacity may be used.

Btu/lb.	- 13,000
Ash, %, maximum	- 10%
Moisture, %, maximum	- 5%
Volatile matter, %	- 26-39
Grindability, Hardgrove, minimum	- 60
Ash Characteristics	
Initial deformation, °F	- 1900°
Ash softening, temp., °F	- 2100° min.
Ash fusion, temp. °F	- 2250° min.

2. Coal Transportation

LILCO has great concern regarding the availability of coal on a continuing reliable basis . . . . It is our evaluation that significant revisions to our coal and ash handling and dust collection equipment is required to place this plant back on coal.

We are concerned over the capacity of the coal piers in the New York harbor to accommodate additional tonnage for unloading into barges. Of the three previous coal unloading piers (Penn-Central, Central Railroad of New Jersey, and the Reading R.R.), only the Reading Pier is in operation. The financial condition of the other two railroads makes questionable their ability to restore their piers to an operating status.

Historic coal deliveries to the E. F. Barrett plant have been by rail to the Jersey side of the Hudson River, at which point, they were floated on barges to a terminal of the Long Island Railroad (LIRR). The LIRR will no longer accept coal on car floats and will not use passenger railroad tunnels under the Hudson and Fast Rivers for transit to Long Island proper. Thus, an all-rail route north to Selkirk, New York, thence south over the Hell Gate Bridge to Long Island, is necessitated.

3. <u>Acquisition and Refurbishment</u>

Phase I - Revisions and additional equipment required to provide reliable operating conditions, exclusive of plume opacity considerations.

(1) Conversion of boiler ash pit, burners and ash system from oil to coal firing.
Lead time 2 weeks

(2) Dredge ash pond for required additional bottom ash capacity.
Lead time 2 months

(3) Rebuild existing coal pile storage area, install impervious liner to prevent ground water contamination, and provide drainage to capture and treat runoff.
Lead time 6 months

(4) Install dust control system at coal pile and railroad car unloading facility.
Lead time 9 months

(5) Alter railroad track egress to LILCO property

from the Long Island Railroad (L.I.R.R.). The LIRR (Metropolitan Transportation Authority) notified LILCO in 1974 that it will not deliver coal under existing railroad track layouts, except in limited delivery increments, to avoid blocking of Long Beach Road for passenger and commercial traffic and emergency vehicles of the Village of Island Park.

Lead time 9-12 months

(6) Rotary railroad car dumper complete with pit, building, tracks, positioner, etc.

Lead time 2 years

(7) Installation of waste water treatment system for coal firing. This is necessary for treatment of bottom ash waste water.

Lead time 2 years

(8) Hydrobin capacity is required to handle high ash coal. The hydrobin is used for intermediate storage of bottom ash and to decant out hydraulic ash transfer medium. The installation of a hydrobin is anticipated due to environmental restrictions which would prohibit the hydraulic deposit of ash in previous fields draining into waterways.

Lead time 2 years

(9) Installation of dry fly ash system, ash silo and building, equipment, etc.

Lead time 2 years

Phase I Total

Phase II - Precipitators required to meet efficiency of 98% or higher.

(1) New precipitator parallel to existing unit.

Lead time 3 years

Phase III - SO_2 removal equipment if required by EPA or State. (Present fuel requirement is 0.37% sulfur.)

(1) SO_2 removal system.

Lead time 3 years (minimum)

4. <u>Power Plant Outage Time</u>

Upon receipt of notification, conversion from oil to coal firing with existing equipment can be accomplished with a two week outage for each unit. Such estimate is based on converting to coal firing with original design conditions and is exclusive of present day environmental standards.

5. <u>Lead Time</u>

The coal handling and stacking out equipment is overhauled and capable of stock-piling coal whenever it is received. The ash system has been checked out and can be operated. However, a minimum amount of ash can be removed before the ash field has to be dredged. The boiler is in a state of readiness such that it requires a two week shutdown for actual boiler conversion work. This would also be sufficient time to develop the necessary coal inventory with existing equipment.

However, a lead time of up to two years to acquire or refurbish the equipment discussed in Response Nos. 4 and 5 would be necessary.

6. Local Laws

State laws that have an effect on coal utilization are Parts 700-703, Title 6, New York State Water Quality Standards and Part 201.9 of 6 NYCRR, air pollution control.

In addition, Barrett is located in the Town of Hempstead which has a noise code in Chapter 144.

APPENDIX X-4 BERGEN POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Public Service Electric and Gas Company:

1. Original design coal specifications:

Bergen Nos. 1 & 2 Units

Heating value	- 13,000 Btu/lb	as received
% Sulfur	- 3.0	as received
% Ash	- 10.0	as received
% Volatile matter	- 36.0	as received
Grindability	- 60 Hardgrove	
Ash fusion temp.	- 2100 F	

Some variations in the original specifications could be tolerated if these variations are not too great. Maximum and minimum limits for the boilers are:

Heating value	- 12,800 Btu/lb	Mininum as received
% Ash	- 11%	Maximum as received
Volatile matter	- 22%	Minimum as received
Grindability	- 55 Hardgrove	Minimum
Ash fusion temp.	- 2300 F	Maximum

2. Coal Conversion Costs Are:

COAL CONVERSION DATA AND COSTS

	Bergen Nos. 1 & 2	
Data		
Capacity (MW)	280	283
Initial service (year)	1959	1960
Last burned coal (year)	1971	1971
Maximum lead time-material (weeks)	40	
Maximum lead time-conversion (weeks)	52	
Boiler outage required (week)	9	9
Costs		
Coal handling equipment	$ 588,500	
Pulverizers, burners, boilers	372,000	
Ash and dust disposal	2,298,500	
Pipeline penalty	4,450,000	
Outage replacement energy		
Total conversion costs	$7,709,000	
Additional Annual Operating Costs		
Labor	$ 407,000	
Material	200,000	
Ash and dust disposal	652,000	
Total additional annual operating costs	$1,259,000	

COAL CONVERSION
EQUIPMENT COSTS AND LEAD TIME
NOS. 1 AND 2 UNITS
BERGEN GENERATING STATION
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(1975)

Equipment	Cost	Conversion lead time (weeks)
Coal Handling Equipment		
Redlers	$ 200,000	45
Coal silos & vibrators	18,500	21
Car thawing shed	8,500	7
Car dumper	10,500	28
Conveyors	124,500	42
Bradford breaker	18,500	34
Crushers	20,500	12
Swing Boom & swing boom rest	7,500	28
Transfer tower	14,000	16
Miscellaneous	16,000	6
Bulldozer	150,000	10
Total	$ 588,000	
Pulverizers, Burners, Boilers		
Combustion control	$ 2,000	27
Feeder tables & assoc. equipment	36,000	33
Pulverizer mills	64,500	44
Coal burning air syst.	20,500	11
Boiler tubing	110,000	24
Sootblowers	125,500	32
Air heaters	8,500	16
Boiler penthouse pressurizing fans	5,000	10
Total	$ 372,000	
Ash and Dust Disposal		
Dust transport system	$ 29,500	30
Ash sluice system	27,000	30
Slag system	42,000	48
Rebuild ash pond and Water treatment	2,200,000	52
Total	$2,298,000	

APPENDIX X-5 CROMBY POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Philadelphia Electric Company:

"1. Original specification coal characteristics, as fired, for Cromby Unit No. 2.

Btu/lb		13,700
Sulfur, %		1.5
Ash, %		7.0
Volatile, %		26.0
Ash fusion temp. -	Softening	2590°F
	Liquid	2670°F

2. Range of characteristics compatible with design tolerance.

		Maximum	Minimum
Btu/lb		-	13,100
Sulfur, %		3	1.5
Ash, %		10	-
Volatile, %		40	24
Ash fusion temp. -	Softening	-	2,500
	Liquid	-	2,600

3. Coal and Transportation Information

(a) Availability of coal and transportation

Based on the quality of coal received in 1974, the additional coal required for Cromby No. 2 would be difficult to obtain and meet the specifications of the equipment. New mines would have to be opened with cleaning equipment to produce the quality required. Locomotive power and roadbed should be adequate; car availability could be inadequate.

(b) Transportation Companies

Penn Central Railroad and lateral lines
Baltimore and Ohio Railroad and lateral lines
Western Maryland Railroad
Reading Company

(c) Estimated Increased Coal Consumption

Approximately 540,000 tons/year for next five years.

4. Equipment refurbishing required and estimated labor and material cost.

   (a) Inspect coal burners and repair as required. Inspect and repair mills as required. Labor and material estimate is $10,000.

   (b) Clean and inspect the ash handling system. Inspect electrostatic precipitator and replace wiring as required. Install hopper unloading rotary valves. Labor and material estimate is $15,000.

   (c) Replace tube shields on superheater tubes. Labor and material estimate is $20,000.

   (d) Clean and inspect combustion control for coal-firing. Repair as required and adjust. Labor and material estimate is $5,000.

   (e) The increased operations and maintenance cost for coal firing is estimated to be 0.05¢/kWh.

5. Estimated Outage Time Required

   Two weeks

6. Estimated Lead Time Required

   Approximately one month to obtain material, plan outage, and schedule manpower. Coal inventory is already on hand for coal firing of Unit No. 1.

Cromby Unit No. 2 is expected to retire in the early 1990's. However, this date will be subject to review as the date approaches. Final retirement date will be determined by the in-service dates of new capacity additions and the system capacity requirements at the time.

7. State or Local Laws or Policies

   Excluding air pollution controls, no other limitations are known."

APPENDIX X-6 HOWARD M. DOWN POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the City of Vineland Electric Utility:

"Original Coal Specifications

Last contract - 1972:

% Moisture	3.5 maximum
% Volatile	22 to 37 maximum
% Ash	8.5 maximum
% Sulfur	1.0 maximum
BTU/lb	14,000 minimum
Ash Fusion - Temp. °F	2,550 minimum
% $Fe_2 O_3$ in Ash	15 maximum
Grindability (Hardgrove Index)	85 maximum
Burning characteristics	Light to medium caking

"Maximum and Minimum Values of Coal

Unit No. 10 (Pulverizers)

% Moisture	2.5 - 10
% Volatile	20 - 40
% Fixed Carbon	40 - 70
% Sulfur	1 - 3.5
% Hydrogen	-
% Oxygen	-
% Ash	6.5 - 15
Heat Value - as fired - BTU/lb	12,000 - 14,000
Ash Softening Temp. °F	2,000 - 2,500
Grindability, Hardgrove	45 - 80

"The most recent purchases of coal were from the Island Creek Coal Sales Company of West Virginia and the Crown Coal and Coke Company of Pennsylvania.

"Coal must be available under contract consistent with the public bidding laws of the State of New Jersey. The Central Railroad (CRR) of New Jersey branch, to Bridgeton, must be maintained in good condition to provide a reliable supply route.

"Coal is delivered to the Down Station by the CRR of New Jersey. They would receive the cars from various connecting railroads according to the point of origin.

"Estimated Annual Coal Consumption Unit 10: 80,000 tons.

"The Down Station coal-handling and ash-handling systems are operable and in satisfactory condition. The firing equipment on the No. 10 unit is operable. Storage facilities will accommodate approximately ten (10) days supply of coal.

"Actual conversion of Unit No. 10 involves very minimal cost. It will be necessary to stock replacement parts for pulverizers and associated equipment. This may require a ten thousand dollar ($10,000) investment.

"Unit No. 10 can be converted to coal-firing with a few hours of partial outage.

"Coal handling facilities can be changed from standby to operational status in about one (1) week. If coal were obtained initially on a spot purchase basis, it would probably require two (2) months or more to build an adequate coal inventory.

"No laws or policies other than the Air Pollution Control limit the utilization of coal in the Down Station."

APPENDIX X-7 FOX LAKE POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Interstate Power Company:

Coal Specifications Compatible with Design Tolerances

	Maximum	Minimum
Btu/lb	12,000	8,000
Sulfur	-	0.5%
Ash	12.0%	-
Volatile Matter	40.0%	25.0%
Ash Fusion Temp.	2200°F	1900°F

"The main coal supplier is Westmoreland Resources, Sarpy Creek, Montana. No coal or transportation difficulties are encountered. BN and CMSTP & P railroads are the principal transportation companies.

"Based on 100% maximum capacity coal burning, coal consumption would average 140,000 tons/yr based on 8,450 Btu/lb coal.

"Additional equipment (i.e. bunkers, feeders, pulverivers, burners, piping, soot blower, and controls) would have to be purchased to attain 100% capacity on coal at a cost of $1,500,000.

"Existing coal storage will handle 75,000 tons which should be adequate.

"An estimated outage time of one month and a lead time of eighteen months is needed to attain 100% coal burning capacity.

"No existing state or local laws other than air pollution control laws would limit utilization of coal.

APPENDIX X-9 HUDSON POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Public Service Electric and Gas Company:

1. Original Design Coal Specifications:

Hudson No. 1 Unit:

Heating value	- 13,000 Btu/lb	as received
% Sulfur	- 3.0	as received
% Ash	- 10.0	as received
% Volatile matter	- 36.0	as received
Grindability	- 55 Hardgrove	
Ash fusion temp.	- 2100 F	

Some variations in the original specifications could be tolerated if these variations are not too great. Maximum and minimum limits for the boiler is:

Heating value	- 12,800 Btu/lb	Minimum as received
% Ash	- 11%	Maximum as received
% Volatile matter	- 22%	Minimum as received
Grindability	- 55 Hardgrove	Minimum
Ash fusion temp.	- 2300 F	Maximum

2. Coal Conversion Costs Are:

COAL CONVERSION DATA AND COSTS

	Hudson No. 1
Data	
Capacity (MW)	383
Initial service (year)	1964
Last burned coal (year)	1970
Maximum lead time-material (weeks)	40
Maximum lead time-conversion (weeks)	52
Boiler outage required (weeks)	8
Costs	
Coal handling equipment	$ 3,833,500
Pulverizers, burners, boilers	451,000
Ash and dust disposal	4,868,000
Pipeline penalty	3,350,000
Outage replacement energy	
Total conversion costs	$12,532,500
Additional Annual Operating Costs	
Labor	$ 721,500
Material	360,000
Ash and dust disposal	452,000
Total additional annual operating costs	$ 1,533,500

COAL CONVERSION
EQUIPMENT COSTS AND LEAD TIME
NO. 1 UNIT
HUDSON GENERATING STATION
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(1975)

Equipment	Cost	Conversion lead time (weeks)
Coal Handling Equipment		
Modify coal handling system	$3,640,000	52
Silo level controls	21,500	12
Crushers	22,000	12
Bulldozer	150,000	
Total	$3,833,500	
Feeders, Burners, Boiler		
Combustion control	$ 5,500	3
Fuel detectors	3,000	41
Gravimetric feeder	26,500	31
Coal conduits	33,000	29
Coal inlet gates	8,500	4
Cyclone wear blocks	24,000	17
Auxiliary cooling	5,000	2
Water jacket	8,500	4
Sandblast cyclones	6,500	2
Restud cyclones	126,000	18
Cyclone slag tags	17,000	4
Gunnite cyclones	9,000	2
Air dampers	12,500	3
Reheater shields	22,500	7
Deslag furnace	1,000	2
Floor	78,500	18
Slag tap	1,500	1
Cinder trap	2,000	1
Sootblowers	60,500	24
Combustion control	5,500	3
Total	$ 451,000	
Ash and Dust Disposal		
Dust transport system	$ 100,000	32
Ash sluice system	69,000	29
Slag system	99,000	32
Rebuild ash pond & water treatment	4,868,000	52
Total	$4,868,000	

APPENDIX X-9 JONES STREET POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Omaha Public Power District Company:

Boiler #27 at the Jones Street Power Station was converted from coal to oil/gas in 1972. This was done because the station could not meet air quality standards and the cost to install air quality control equipment was prohibitive vis-a-vis the age, available space, and worth of the plant. Furthermore, it was agreed that no additional variances would be requested beyond June 1, 1973.

In connection with this conversion, two 1,000,000-gallon oil tanks were installed in 1972, and two more (1,600,000-gallon and 1,300,000-gallon) were installed in 1973. These tanks were all placed in the old coal handling area, and also serve the two gas turbines installed on the Station. Since that time, much of the coal conveying and other coal handling equipment has been removed and disposed of.

The Omaha Public Power District is presently an "interruptible customer" of Northern Natural Gas Company and has been for several years. The District has been informed by Northern Natural Gas that 1976 will be the last year that gas will be available to fire boilers.

The Jones Street Power Station now consists of two old boilers and turbines and is used for peaking operations only as is evidenced by the following 1974 data:

	BOILER #26	BOILER #27
Year Built	1949	1951
Net Capacity	36 MW	47 MW
Hours of Operation	856	920
% of Year	9.8%	10.5%
Capacity Factor	7.9%	7.4%

Total Oil Consumed	109,986 gallons (both boilers)
Total Gas Consumed	696,000 MCF (both boilers)
1977 Projections:	
Total Oil	760,000 gallons #2 oil (18,095 bbls)
Total Gas	NONE

To convert one of these two boilers, or both, back to coal at this stage of plant life is not only economically infeasible, it borders on the impossible due to the considerations enumerated below.

1. Because of the age and efficiency of the boilers, air quality standards, including particulate limits, could not be met without the addition of air quality control equipment. This equipment would have to be installed in the former coal storage area, now occupied by fuel storage tanks. This would necessitate the relocation of the fuel storage tanks and the establishment of a new coal storage area.

2. There are no ash settling ponds or similar facilities at the site. With no means of handling coal pile runoff or sluicing water used in the ash handling system, water quality standards could not be met.

3. The Jones Street Power Station is located on the Missouri River in downtown Omaha and is surrounded by other commercial facilities. The size of the site is approximately 16 acres. With no room to expand, the addition of any major facility, such as a new fuel oil storage area, coal storage area, or ash settling pond is not possible.

4. The deteriorated condition of the remaining coal and ash handling equipment, and the need to rebuild large segments of major coal handling systems already removed would be costly and uneconomical.

In conclusion, should the Omaha Public Power District be directed to convert the Jones Street Station to coal, serious consideration would have to be given to decommissioning the plant rather than embarking on a costly, uneconomical conversion.

Boiler No. 27 was designed to burn Kansas Bituminous coal from the mines near Pittsburg, Kansas. The characteristics are as listed below.

Kind - Kansas Coal, Bituminous
Grindability - 55
Surface Moisture, % - 6
BTU/LB - 11,380
Sulphur, % - 5.24
Ash, % - 16.70
Volatile Matter, % - 33.70
Ash Temperature, °F
    Init. Def. - 1894
    Liquid - 1955
Slagging Index, R_S - 2.96 (Severe slagging coal)
Fouling Index, R_F - 0.74 (High fouling coal)

The sintering characteristics of the coal have not been determined as such.

Boiler No. 27 has not burned other types of coal to any extent. However, it is felt that Hanna, Wyoming coal could be burned with some reduction in capacity. Kansas coal is no longer available and to determine the feasibility of burning other types of coal would require a detailed engineering study which has not been done. Hanna, Wyoming coal is available at the present time and the characteristics are listed below.

Kind - Wyoming, Sub-bituminous

	Max.	Min.
Grindability	N.A.	N.A.
Moisture, %	13.8	12.0
BTU/LB	10,800	10,000
Sulphur, %	0.95	0.75
Ash, %	13.8	5.3
Volatile Matter, %	N.A.	N.A.
Ash Temperature, °F		
Init. Def.	N.A.	N.A.
Liquid	N.A.	N.A.

N.A. - Not Available

In order for the Omaha Public Power District to be capable of burning coal in their Jones Street Station Boiler #27, it would be necessary to purchase and install, modify, or repair the following items:

1. Coal Handling System

		Cost
A.	Purchase Locomotive to move coal	$100,000
B.	Purchase coal handling scraper	125,000
C.	Install R.R. trackage over coal scale, track hopper, repair remainder of RR track	75,000
D.	Purchase and install track scale and scale house	100,000
E.	Purchase and install shaker house and shaker car	60,000
F.	Purchase and install coal pit, vibrating screens, coal conveyor or vert. lift	100,000
G.	Purchase and install stocking-out conveyor system	200,000
H.	Purchase and install vertical coal lift basement to transfer belt (w/some salvage material)	20,000
I.	Purchase and install transfer belt, coal sampling and weighing system	30,000
J.	Purchase and install horizontal drag conveyor above bunker	20,000
K.	Purchase and install 480 volt motor control center and wiring for coal handling	25,000
L.	Rework offices because of interference with coal conveyor	3,000
	Cost	$858,000

2. Storage Facilities for Coal

		Cost
A.	Purchase land and provide diking for control of surface water run-off	$125,000
B.	Process system for run-off water	10,000
	Cost	$135,000

3. Ash and Dust Handling System

		Cost
A.	Purchase and install ash hydrobin, recir. system, ash piping, and ash unloading equipment	$701,000
B.	Purchase and install dry fly ash silo, dustless unloader, and dry unloader	105,000
C.	Purchase and install dry fly ash pneumatic conveyor system	114,000
D.	Purchase dump truck	10,000
	Cost	$930,000

4. Additions and Modification to Boiler No. 27 to Burn Coal

		Cost
A.	Purchase and install 480 volt motor control center for equipment motors	$ 20,000
B.	Purchase and install new coal burners and coal burner piping	30,000
C.	Purchase and install new controls for coal burning on boiler gauge board and field installed panels	60,000
D.	Modify burner deck oil burning management control system	15,000
E.	Relocate oil piping, controls, etc., on burner front to accommodate new coal burners	5,000
	Cost	$130,000

5. Maintenance of Existing Coal Burning Related Equipment

		Cost
A.	Repair sluice water pumps and replace piping	$ 12,000
B.	Repair ash removal pumps, etc.	5,000
C.	Repair boiler ash hopper	5,000
D.	Repair clinker grinder	3,000
E.	Overhaul coal pulverizers, etc.	5,000
F.	Repair soot blowers, soot blower steam piping and valves	2,000
	Cost	$ 32,000

6. Storage Facilities for Coal

Since the District has used its former coal storage area for the installation of two (2) oil fired gas turbines, and four (4) large (2 - 1,000,000, 1 - 1,600,000, and 1 - 1,300,000 gal. each) oil storage tanks that area is no longer available. In order to store coal at the Jones Street Power Station, additional land would have to be purchased, cleared and necessary diking constructed to contain surface water run-off from the coal pile.

The costs associated to restore coal firing capability are as follows:

1.	Coal Handling System	$ 858,000
2.	Storage Facilities for Coal	135,000
3.	Ash and Dust Handling System	930,000
4.	Additions and Modifications to Boiler #27 to Burn Coal	130,000
5.	Maintenance of Existing Coal Burning related equipment	32,000
	Subtotal	$2,085,000
6.	Engineering Costs (15% of #1-#5)	312,750
7.	Overhead and Interest (15% of #1-#6)	359,660
	TOTAL RESTORATION COSTS	$2,757,410

The estimate of operating and maintenance cost differential per year associated with the necessary changes are as follows:

1.	Maintenance cost differential/year	$25,000
2.	Operational cost differential/year	$60,000

APPENDIX X-10 LOVETT POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration (FEA) by the Orange and Rockland Utilities:

1) Maximum and Minimum values for types of coal compatible with boilers' design tolerances.

	Lovett #4	
	Min.	Max.
Btu/lb.	12,000	-
% Sulfur	0	4.0
% Ash	0	15.0
% Volatile matter	30.0	-
Ash softening temp.	2,150°F	-

	Lovett #5	
	Min.	Max.
Btu/lb	12,000	-
% Sulfur	0	4.0
% Ash	0	15.0
% Volatile matter	30.0	-
Ash softening temp.	2,335°F	-

2) Anticipated acquisition or refurbishing of ash handling facilities and costs in 1975 dollars.

<u>Water Quality</u>

Ash settling pond refurbish and waste treatment facilities $1,900,000

<u>Environmental Noise</u>

Sound-proof coal car Shaker Building $ 120,000

3) Lead time to restore coal firing capability:

Settling pond and waste treatment - 1 1/2 years
Sound proof coal car shaker building - 1 year

a. Lead time is not necessary for initial operation if variance is granted for noise and water quality standards.

4) Projected capacity factors:

Capacity factors -	Unit No. 4	Unit No. 5
1974 actual	909,252 MWH output 187 MW x 8,760 = 0.56	1,125,871 MWH output 202 MW x 8.760 = 0.64
1975	0.46	0.37
1976	0.43	0.30
1977	0.47	0.35
1978	0.50	0.39
1979	0.55	0.45

APPENDIX X-11 MUSTANG POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Oklahoma Gas and Electric Company:

"We have not purchased coal for the plant since 1963 when we bought 100 tons. The last purchase prior to that was in 1954. Past supplier's were Benbow Coal Company (1963) and Leavell Coal Company (1954).

"This plant can be supplied only by rail. The only carriers possible are the Chicago, Rock Island and Pacific railroads.

"We had in 1973 only 1100 tons of coal in storage (1.7 burn days) and the maximum amount of coal we have ever had is 5900 tons or 3.9 burn days. The maximum storage capacity is 7800 tons for 5.3 burn days at present capacity factor of 33%.

"In short, the plant was designed and built to burn coal on an emergency stand-by basis and has been operated in that manner.

Original Coal Specifications

Btu/lb	11,020
% Sulfur	1.1
% Ash	16.4
% Volatile Matter	30.2
% Moisture	5.5
Ash Fusion Temp.	1900-2000°F

"At present rates, the fuel cost will double on this unit if coal is burned. The estimated cost for equipment is $7,900,055, for operations and maintenance $731,000 per year, excluding the fuel.

APPENDIX X-12 POSSUM POINT POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by Virginia Electric and Power Company:

The minimum and maximum values of coal compatible with Vepco power plants design tolerances are as follows:

Btu/lb	11,300* - 14,000
Percent Sulfur	0.5 - 4.0
Percent Ash	2.5 - 20
Percent Volatile matter	15 - 34
Ash Fusion Temperature (F)	2,300 - 2,900

* If Btu/lb is below 11,800 and Hardgrove Grindability is less than 75, there is a possibility of reduction in capability because of mill capacity.

Below are listed the work required, on Boilers 2 through 4 at Possum Point power plant, to convert to coal firing. These are estimates and after inspection of the boilers and associated coal auxiliaries additional work may be required at additional cost, time, and effort.

<u>Boiler</u>

Burner corner repair (buckets, dampers)
Relocation of side ignitors and oil guns
Replace cold end elements on air preheaters
Repair IR-soot blowers
Remove refractory from furnace walls

Change-out orifices in lower drums
Recalibration of boiler controls
Repairs to electrostatic precipitators

Coal Handling System

Inspection and repair of coal feeders and mills

Ash Handling System

Reinstall dry fly ash handling system
Bottom ash pond is no longer available due to construction of Unit 5. A small retention pond will have to be constructed to handle bottom ash until a permanent pumping system to the fly ash ponds can be constructed.

Coal Storage Equipment

Repair railroad tracks and install 1,500 feet of new track
Repair coal unloading equipment (car shaker, feeders, crusher, conveyors and scales)
Obtain locomotive and tractor

The estimated cost to restore coal firing capability for Possum Point is as follows:

Possum Point 2	$ 35,000
Possum Point 3	$ 55,000
Possum Point 4	$ 88,000
Coal Handling Equipment	$179,000
Temporary Bottom Ash Pond	$220,000
Total - Possum Point 2-4	$577,000

The estimated annual increase due to conversion to coal firing using 1975 Estimated Annual Expenses would be:

Possum Point

Operation	$ 45,000
Coal Handling	$150,000
Maintenance	$190,000
Total - Possum Point 2-4	$405,000

"The estimated outage time required to make necessary changes and convert the units to coal firing, if no major problems are encountered or if work beyond that envisioned has to be done because of inspection findings."

Possum Point 2	3 weeks
Possum Point 3	3 weeks
Possum Point 4	4 weeks

Total time required for Possum Point - 10 weeks

APPENDIX X-13 RAVENSWOOD POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Consolidated Edison Company:

> "The questions (on the FEA information request) were answered on the basis that any order to convert to coal firing would be on a non-emergency basis, and would be for the long term. No allowance or consideration was made for an AQCS further than adequate precipitators. The cost figures used are estimates and should be used as order of magnitude numbers."

Original coal specifications for Boiler 30 is shown below:

	Boiler 30
HHV, Btu/lb	14,080
Ash,%	7.2
Volatile, %	36.5
Ash fusion temp.,°F	1900-2300
Moisture, %	3.4
Free Carbon,%	52.9
Grindability	63

	Estimated cost, $	Estimated lead time & construction time	Estimated Plant out time
Ravenswood Unit 30 North			
1) Overhaul & remove precipitator blanks	20,000	3 wk.	1 wk.
2) Overhaul bottom ash system	25,000	4-6 mo.	1 wk.
3) Restore fly ash system & silo	300,000	4-6 mo.	1 wk.
4) Overhaul raw coal system	100,000	4-6 mo.	None
5) Overhaul pulverizers & burners	100,000	1/2 - 1 yr.	3 wk.
6) Overhaul controls	20,000	1 mo.	1 wk.
Unit 30 South			
1) Repair precipitator	2,200,000	4 mo.	1 wk.
2) Same as Unit 30 N	Incl. in Un. 30 N		
3) Same as Unit 30 N	Incl. in Un. 30 N		
4) Same as Unit 30 N	Incl. in Un. 30 N		
5) Same as Unit 30 N & repair damaged ductwork	175,000	1/2 - 1 yr	None
6) Same as Unit 30 N	Incl. in Un. 30 N		

"No coal storage (on ground). All coal deliveries by barge, direct to bunkers. No bottom ash or fly ash disposal on site.

The differential operation and maintenance cost estimates are as follows:

	Operation	Maintenance	Total
Unit 30, $	299,059	277,863	576,922

APPENDIX X-14 RIDGELAND POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Commonwealth Edison Company:

(1) Original specification coal for Ridgeland based on Illinois Seam 6 coal is analyzed as follows:

Moisture, %	15.00
Ash, %	15.00
Carbon, %	52.00
Hydrogen, %	3.85
Sulfur, %	4.65
Oxygen, %	8.70
Nitrogen, %	0.80
Btu/lb	10,000
Ash fusion temp.	2,000

"Performance estimates and criteria shall be based on the coal specified above. The entire steam generating and coal burning equipment, however, shall be able to develop the maximum capacity and operating efficiency with other Illinois, Indiana, and Kentucky coals having heating values between 10,000 and 12,500 Btu/lb; ash fusion temperatures varying between 1950°F and 2300°F and moisture up to 15%."

(2) Range of characteristics compatible with design tolerance:

	Maximum	Minimum
Btu/lb		10,000
Ash, %	15	-
Sulfur, %	4.5	-
Ash sintering strength, psi	5,000	-
Ash fusion temperature	2,250	-

(3) Identification of facilities to be acquired or refurbished:

Equipment/facilities	Cost, $
Coal unloading equipment - west dock	456,000
- east dock	100,300
Coal moving equipment	10,000
Conveyor belt junction hoppers, gates, and belt system	81,000
Breaker house	49,000
Ash and slag handling	45,000
Boilers 1 through 6 - refitting required for coal firing	149,200
Boiler instrument and controls	6,000
Ash handling systems	7,000,000
Coal and ash pile water runoff control	3,300,000
Air heater and boiler fire side wash water control facilities	2,500,000
Misc. drain collection, discharge, and control facilities	1,700,000
Total cost of anticipated acquisition refurbishing of facilities	15,396,500

(4) Total increase in annual operating and maintenance construction is estimated at $2,900,000.

- Other Considerations

Increased boiler maintenance can be expected with coal-firing due to more rapid cyclone tube wear and due to increased superheater wastage and failure because of higher furnace temperatures. This will result in more frequent Scheduled and Emergency outages. Availability would be expected to drop about 6%.

Superheater tube replacement is an unkown factor. We can expect that the more frequent failures will require replacement of sections of tube banks within a couple of years of conversion.

Boilers 1-4 might spend up to $150,000 each.
Boilers 5 and 6 might spend up to $300,000 each.

Manpower problems will include, in addition to hiring of the 24 men for coal plant and operating:

a) Training of these new men for skilled and unskilled positions. Former coal plant people have left Ridgeland. Most of those remaining at the Station are in other classifications and will not desire returning to coal plant work even (as some have indicated) if a promotion is involved.

b) Selecting two men as supervisors for the coal plant. We may have to go outside the station and train them to handle our equipment.

c) Possible loss to retirement of operating people due to the harder work which can be encountered in handling wet coal, slag and ash problems, both at the furnace tap or slag tank and dust hoppers, and control problems due to tripouts and difficulty of lighting off the cyclone burners particularly on a cold boiler. For maintenance and more frequent outages resulting in harder, dirtier work, callouts and longer hours.

We have two Shift Engineers who have requested retirement at age 58 in 1975.

The number and ages of supervisors and employees of concern are:

Supervisors

Total	33
No. at age 58 or 59	3
No. at age 60 to 64	4

Employees

Total	179
Skilled	
No. at age 58 or 59	13
No. at age 60 to 64	16
Semi-Skilled	
No. at age 58 or 59	4
No. at age 60 to 64	2

In arriving at repair costs no consideration was given to repair of car dumper. This can handle only the lower height cars up to 100 tons. It cannot handle tall railroad cars.

(5) A one month outage would be required for each boiler. An outage of either Boiler 1 or Boiler 2 will decrease the capacity of Unit 1 by approximately one-half. A similar relationship exists with respect to Boilers 3 and 4, and Unit 2. The outage of Boiler 5 will mean the total loss of capacity of Unit 3. The outage of Boiler 6 will mean the total loss of capacity of Unit 4. As discussed on page 3 of cover letter reference no. 2, Units 1 and 2 cannot be out of service at the same time, and there are substantial constraints against Units 3 and 4 being out of service simultaneously for periods as long as a month.

Because of the nature of the boiler rehabilitation work, the boilers should not be returned to oil firing after being refitted for coal. Therefore, the refit work would be scheduled to coincide with the stockpiling of adequate amounts of coal for start-up. Such a stockpile cannot be established until a system for collecting and treating the coalpile rainfall runoff is installed and made ready to operate.

(6) The restoration of coal firing capability at Ridgeland Station is contingent upon two major construction and reconstruction activities. These are: 1) the construction of water quality systems and 2) the restoration of existing coal associated equipment. The critical path activities are illustrated in Figure 1. You will note that the most severe time constraint is imposed by the

construction of the system to handle the coal and ash pile runoff. The end date for this activity is 45 months after start of design. The boiler conversion activities proceed at the rate of a boiler per month and the entire conversion is completed approximately 51 months after initiation.

The estimated time to build an adequate coal inventory is 100 days. This is based on starting to build the storage pile before actual coal burning starts. A coal supply for ninety days is considered adequate at Ridgeland. The estimated buildup is accomplished at 2500 tons per day. This is not a critical path activity.

(7) Identify any state or local laws or policies, other than air pollution control laws or policies, that might limit the utilization of coal by the power plant.

In summary, we cannot verify at this time whether compliance with all of the regulations cited is technically feasible (and indeed, such a determination cannot be finally made until a specific air pollution control mode is chosen). What <u>is</u> certain is that any program of attempted compliance will strongly impact both the cost and the scheduling of any coal conversion. These impacts are treated in sections (4) and (6), above.

APPENDIX X-15 RIVERTON POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Potomac Edison Company.

Riverton power plant's original specification for coal and the maximum and minimum values for other types of coal are presented below:

Unit's original specification coal as outlined in Boiler Proposal:

Btu/lb.	-	12,000 Ultimate Analysis
Moisture	-	8.0% Proximate Analysis
Volatile Matter	-	29.0% Proximate Analysis
Fixed Carbon	-	51.0% Proximate Analysis
Ash	-	12.0% Proximate Analysis
Grindability	-	55 Hardgrove Minimum

Btu/lb.	-	10,800 minimum.
% Sulfur	-	There is no coal with the 0.2% sulfur required to meet ambient requirements.
% Ash	-	25% maximum for handling and maintenance considerations. There is no coal with the less than 1% ash that would be required to meet emission requirements. This unit does not have an electrostatic precipitator, and one would have to be installed.

% Volatile and Ash Slagging/Sintering - We have never encountered difficulty with either of these items with bituminous coal on this boiler.

Provided below are listed the coal conversion costs and coal handling equipment requiring maintenance.

Item	Comment	Cost	Outage Time
Install coal burners, etc.	Equipment available. Some 2 weeks would be necessary to plan for the outage work.	$50,000	6 wks.

In addition to the above item:

(a) Differential plant manpower cost increase to use coal instead of oil - $64,000/year.

(b) Some coal firing items were not maintained and will require additional maintenance after returning to coal. These include conveyor belting, pulverizers, coal feeders, etc. They should not provide deterrents to returning to coal firing.

(c) Water quality regulations may require expenditures, the amount of which cannot now be determined if the unit is reconverted to coal firing.

APPENDIX X-16 VIENNA POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by Delmarva Power and Light Company:

Unit 8 was designed and constructed to use heavy oil as the only fuel. No space is available for the installation of coal bunkers, pulverizers, coal pipes and conveyors. Extensive boiler modifications would be required and even then, the effective capacity of the unit would be greatly reduced because of furnace design limitations. Therefore, this unit has not been considered as a candidate for conversion to coal.

Tabulated below are the capacities and ages of the remaining units at the station:

Unit	Capacity - MW	Installation Date/Age-yrs.
5	17	1947/27
6	17	1948/26
7	40	1951/23

In view of the age of these units, the extensive capital requirements for coal conversion, their probably future use for cycling service and considering their small size and the resultant minimal savings in oil consumption, we do not believe the expense of conversion to coal is justifiable. Further, a cooling tower serving Unit 8 has been installed in the former location of the coal storage pile. It would be possible to create a new coal pile of reduced size but this would make the reliability of the station more vulnerable to interruptions in coal supply caused by strikes, transport problems, etc. In addition, a coal pile in close proximity to the Unit 8 cooling tower would have a deleterious affect on the cooling tower and the water in the tower with an adverse affect on the reliability of this unit.

We believe that these units could be converted to coal and possibly would not violate the primary air standards. Improved particulate collection and SO_2 removal would be required by 1978 to meet the SIP standards. However, there does not appear to be space available for the installation of scrubbers.

<u>Conversion Costs</u>

A. Convert to coal and possibly comply with primary air standards - no SO_2 scrubbing or new particulate removal equipment.

Conversion of Units 5, 6 & 7 to coal	$300,000

B. Differential Annual Operating Costs (50% capacity factor)

Operating & maintenance (excluding fuel)	$ 35,000

<u>Timing of Conversion</u> - no SO_2 scrubbing, no new precipitators

Unit 5	-	1 month
Unit 6	-	6 months
Unit 7	-	8 months

APPENDIX X-17 L. D. WRIGHT POWER PLANT

Given for the purpose of completeness, the following information relative to the fuel conversion was supplied to the Federal Energy Administration by the Department of Utilities:

The original coal specifications for the two units were as follows:

Crawford County, Kansas
Carbon - 49.0%
Ash - 10.0%
Volatie Matter - 34.1%
Sulfur - 3.5%
Moisture - 10.0%
Btu - 12,500/lb
Ash fusing temperature - 1900°F

Presently the coal being fired is from Carbon County, Wyoming with the following analysis:

Moisture - 14 to 16%
Ash - 6 to 10%
Sulfur - 0.6 to 0.9%
Btu - 9,900 to 10,100/lb
Ash fusion - 2,100° to 2,200°F

Present coal storage area is 65,000 tons. There are no facilities for unloading coal during winter weather. L.D. Wright is in the midst of construction a new 91.5 MW addition to the present plant and until this is completed, an increase in the area available for coal storage is limited.

In order to handle the increase discharge of ash, a new ash line will have to be installed, along with additional ponding to contain the ash. Also, an enlarged coal crusher will be needed and conveyor modifications.

With the slagging characteristics of the fuel, additional soot blowers will have to be installed. A new loader will need to be purchased to handle additional coal.

The estimated cost for additional equipment and refurbishing is as follows:

Coal crusher and conveyor modifications	$ 18,000.00
Increase size of railroad siding	50,000.00
New ash line	20,000.00
Coal loader	70,000.00
Ash pond	15,000.00
Upgrading pulverizers - unknown	
	$173,000.00

The additional fuel cost at the present price would be	263,925.00
Extra coal handling cost	25,218.00
Increased operating and maintenance cost	44,306.62
	$333,449.62

Starting in April of 1976, the L.D. Wright plant has a long term contract with the Stansbury Coal Co., Denver, Colorado, to purchase its future coal needs. This amount of coal to be purchased takes into account that the plant will be 100% coal fired by the end of 1976.