TITLE V OPERATION PERMIT APPLICATION

SEMINOLE POWER PLANT

Prepared for:

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

Tampa, Florida

Prepared by:

ECT

Environmental Consulting & Technology, Inc.

3701 Northwest 98th Street

Gainesville, Florida 32606

ECT No. 94331-0200

June 1996

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HARDCOPY SUBMITTAL

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ELECTRONIC SUBMITTAL

INTRODUCTION

The Seminole Electric Cooperative, Inc. (SECI) Seminole Power Plant located in Palatka, Putnam County, Florida is a nominal 1,360 megawatt (MW) electric generation facility. The Seminole Power Plant consists of two steam boilers (Unit Nos. 1 and 2), two steam turbines, a recirculating cooling water system, coal, limestone, fly ash, bottom ash, and flue gas desulfurization (FGD) sludge stabilization facilities, fuel oil storage tanks, water treatment facilities, railcar maintenance, and ancillary support equipment. Unit Nos. 1 and 2 each have a nominal maximum heat input of 7,172 million British thermal units per hour (MMBtu/hr). Unit Nos. 1 and 2 are fired with coal. No. 2 and used on-spec oils are used for startups and flame stabilization.

Operation of the Seminole Power Plant is currently authorized by Environmental Protection Agency (EPA) Prevention of Significant Deterioration (PSD) permit PSD-FL-018 and Florida Power Plant Siting Act (PPSA) Certification PA 78-10. SECI plans to operate the Seminole Power Plant under the terms of the existing permits until the Title V permit is issued in accordance with Rule 62-213.420(1)(b)2., F.A.C.

The SECI Seminole Power Plant qualifies as a Title V Source pursuant to Rule 62-210.200(173), F.A.C., because potential emissions of a regulated air pollutant exceed 100 tons per year. This application package, prepared using Electronic Submission of Application (ELSA) Version 1.2.1, constitutes SECI's Title V permit application for the Seminole Power Plant and is submitted to satisfy the requirements of Rule 62-213.400, F.A.C.

5 signatures

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:
   Richard Midulla
   Senior Vice President, Technical Division

2. Owner/Authorized Representative or Responsible Official Mailing Address:

   Organization/Firm: **Seminole Electric Cooperative, Inc.**
   Street Address: **16313 North Dale Mabry Highway**
   City: **Tampa** State: **FL** Zip Code: **33618**

3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
   Telephone: **(813) 963-0994** Fax: **(813) 264-7906**

4. Owner/Authorized Representative or Responsible Official Statement:

   I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.*

Richard Midulla
Signature

6/13/96
Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**	
2. Professional Engineer Mailing Address: Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 NW 98th Street** City: **Gainesville** State: **FL** Zip Code: **32606**	
3. Professional Engineer Telephone Numbers: Telephone: **(352) 332-0444**	Fax: **(352) 332-6722**

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [X] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emission units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [ ] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature (seal)

6/6/96
Date

* Attach any exception to certification statement.

II.D.1

AREA MAP

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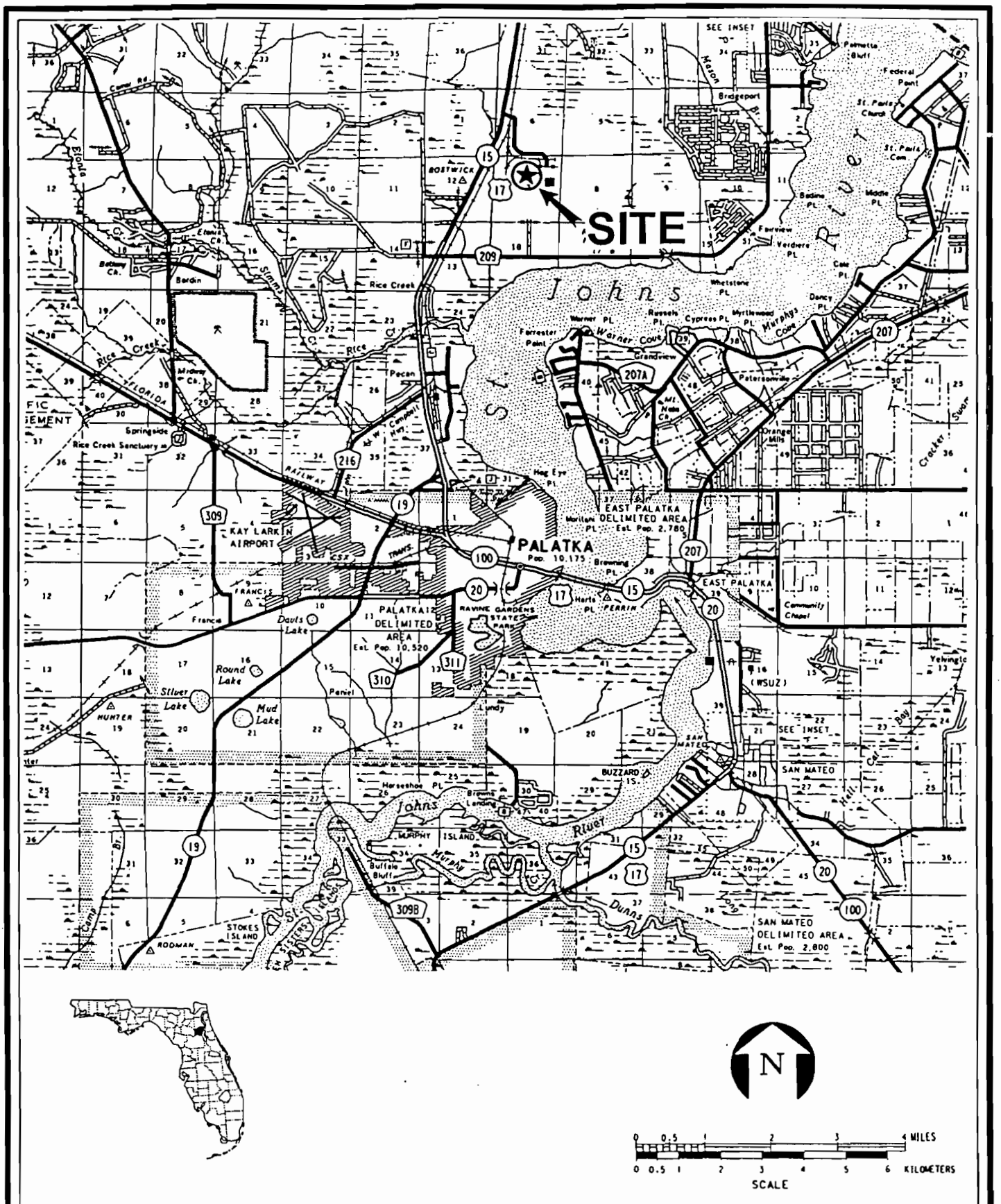

FIGURE II.D.1.

SEMINOLE POWER PLANT LOCATION MAP

Source: D.O.T. Highway Map, 1982.

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Environmental Consulting & Technology, Inc.

II.D.2

FACILITY PLOT PLANS

SEMINOLE POWER PLANT
EMISSION SOURCE KEY

Emission Unit ID	Emission Point ID	Application Emission Unit ID	Emission Unit Description
Combustion Sources			
001	U-001	E.U. 1	Steam Electric Generator Unit No. 1
002	U-002	E.U. 2	Steam Electric Generator Unit No. 2
Coal Yard			
No ID	CH-001a	E.U. 3	Coal Yard; Rotary Unloading Vault
No ID	CH-001b	E.U. 3	Rotary Unloading Vault
No ID	CH-002	E.U. 3	"As Received Transfer Tower
No ID	CH-003	E.U. 3	Conveyor CB-3 to Stacker/Reclaimer
No ID	CH-004	E.U. 3	Stacker to Active Storage Pile
No ID	CH-005	E.U. 3	Reclaimer to Conveyor CB-3
No ID	CH-006	E.U. 3	Conveyor CB-5 to Emergency Storage Pile
No ID	CH-007a	E.U. 3	Emergency Storage Pile Feeder Vault
No ID	CH-007b	E.U. 3	Emergency Storage Pile Feeder Vault
No ID	CH-008a	E.U. 3	Conveyor CB-7A to Crusher Tower Bin
No ID	CH-008b	E.U. 3	Conveyor CB-7A to Crusher Tower Bin
No ID	CH-009a	E.U. 3	Crusher Tower Bin to Crusher

SEMINOLE POWER PLANT
EMISSION SOURCE KEY

Emission Unit ID	Emission Point ID	Application Emission Unit ID	Emission Unit Description
Coal Yard (continued)			
No ID	CH-009b	E.U. 3	Crusher Tower Bin to Crusher
No ID	CH-010a	E.U. 3	Crusher to Conveyor CB-8A
No ID	CH-010b	E.U. 3	Crusher to Conveyor CB-8B
No ID	CH-011	E.U. 3	"As-Fired" Transfer Tower
No ID	CH-012a	E.U. 3	Conveyor CB-9A to Silos
No ID	CH-012b	E.U. 3	Conveyor CB-9B to Silos
No ID	CH-013	E.U. 3	Dozer Operations on Storage Pile
No ID	CH-014	E.U. 3	Active Coal Storage Pile
No ID	CH-015	E.U. 3	Long-Term Coal Storage Pile
No ID	CH-016	E.U. 3	Emergency Coal Storage Pile
Limestone Unloading			
No ID	LS-001	E.U. 4	Truck Unloading and Limestone Breaking
Limestone Handling and Storage			
No ID	LS-002	E.U. 5	Conveyor CB-2 to Crusher House Vibrating Screen
No ID	LS-003	E.U. 5	Conveyor CB-3 to Storage Pile

SEMINOLE POWER PLANT
EMISSION SOURCE KEY

Emission Unit ID	Emission Point ID	Application Emission Unit ID	Emission Unit Description
Limestone Handling and Storage (continued)			
No ID	LS-004	E.U. 5	Storage Pile Reclaim to Conveyor CB-4
No ID	LS-005	E.U. 5	Manual Loading of Reclaim Hopper
No ID	LS-006	E.U. 5	Conveyor CB-5 to Ball Mill Feeder Bin
No ID	LS-007	E.U. 5	Storage Pile
FGD Sludge Stabilization Area			
No ID	FGD-001	E.U. 6	South Lime Railcar Pneumatic Unloading
No ID	FGD-002	E.U. 6	North Lime Railcar Pneumatic Unloading
No ID	FGD-003	E.U. 6	Lime Pneumatic Transfer to Silo V-152
No ID	FGD-004	E.U. 6	Lime Pneumatic Transfer to Silo V-151
No ID	FGD-005	E.U. 6	Fly Ash Transfer to Silo V-142
No ID	FGD-006	E.U. 6	Fly Ash Transfer to Silo V-141
No ID	FGD-007	E.U. 6	Fly Ash Transfer from Silo V-142 to Trucks
No ID	FGD-008	E.U. 6	Fly Ash Transfer from Silo V-141 to Trucks
No ID	FGD-009	E.U. 6	Mixer M-131 (West)
No ID	FGD-010	E.U. 6	Mixer M-132 (East)
No ID	FGD-011	E.U. 6	Landfill

SEMINOLE POWER PLANT
EMISSION SOURCE KEY

Emission Unit ID	Emission Point ID	Application Emission Unit ID	Emission Unit Description
Railcar Maintenance			
No ID	FUG-001	E.U. 7	Railcar Painting
No ID	FUG-002	E.U. 7	Railcar Abrasive Blast Material Storage Bin
No ID	FUG-003	E.U. 7	Railcar Abrasive Blasting
General Plant Fugitives[1]			
No ID	FUG-004	E.U. 8	General Plant-Wide Abrasive Blasting
No ID	FUG-005	E.U. 8	Degreasing
No ID	FUG-006	E.U. 8	Facility Painting
No ID	FUG-007	E.U. 8	Moveable Abrasive Blast Material Storage Bin
No ID	FUG-008	E.U. 8	Plant Unpaved Roads: Flex-Base to Landfill, Loaded Trucks
No ID	FUG-008	E.U. 8	Plant Unpaved Roads: Flex-Base to Landfill, Empty Trucks
Storage Tanks[2]			
Exempt	STR-001	Exempt	No. 2 Distillate Fuel Oil Storage Tank No. 1
Exempt	STR-002	Exempt	No. 2 Distillate Fuel Oil Storage Tank No. 2
Exempt	STR-003	Exempt	Unleaded Gasoline Storage Tank No. 6
Exempt	STR-004	Exempt	Waste Oil Storage Tank No. 9
Exempt	STR-005	Exempt	Waste Oil Storage Tank No. 10

SEMINOLE POWER PLANT
EMISSION SOURCE KEY

Emission Unit ID	Emission Point ID	Application Emission Unit ID	Emission Unit Description
Exempt	STR-006	Exempt	Vehicular Diesel Storage Tank No. 11
Exempt	STR-007	Exempt	Waste Oil Storage Tank No. 23
Exempt	STR-008	Exempt	Waste Oil Storage Tank No. 24
Exempt	STR-009	Exempt	Vehicular Diesel Storage Tank No. 25

[1] Unregulated emission unit; sources not shown on location or process flow diagrams.
[2] Exempt emission unit; sources not shown on location or process flow diagrams.

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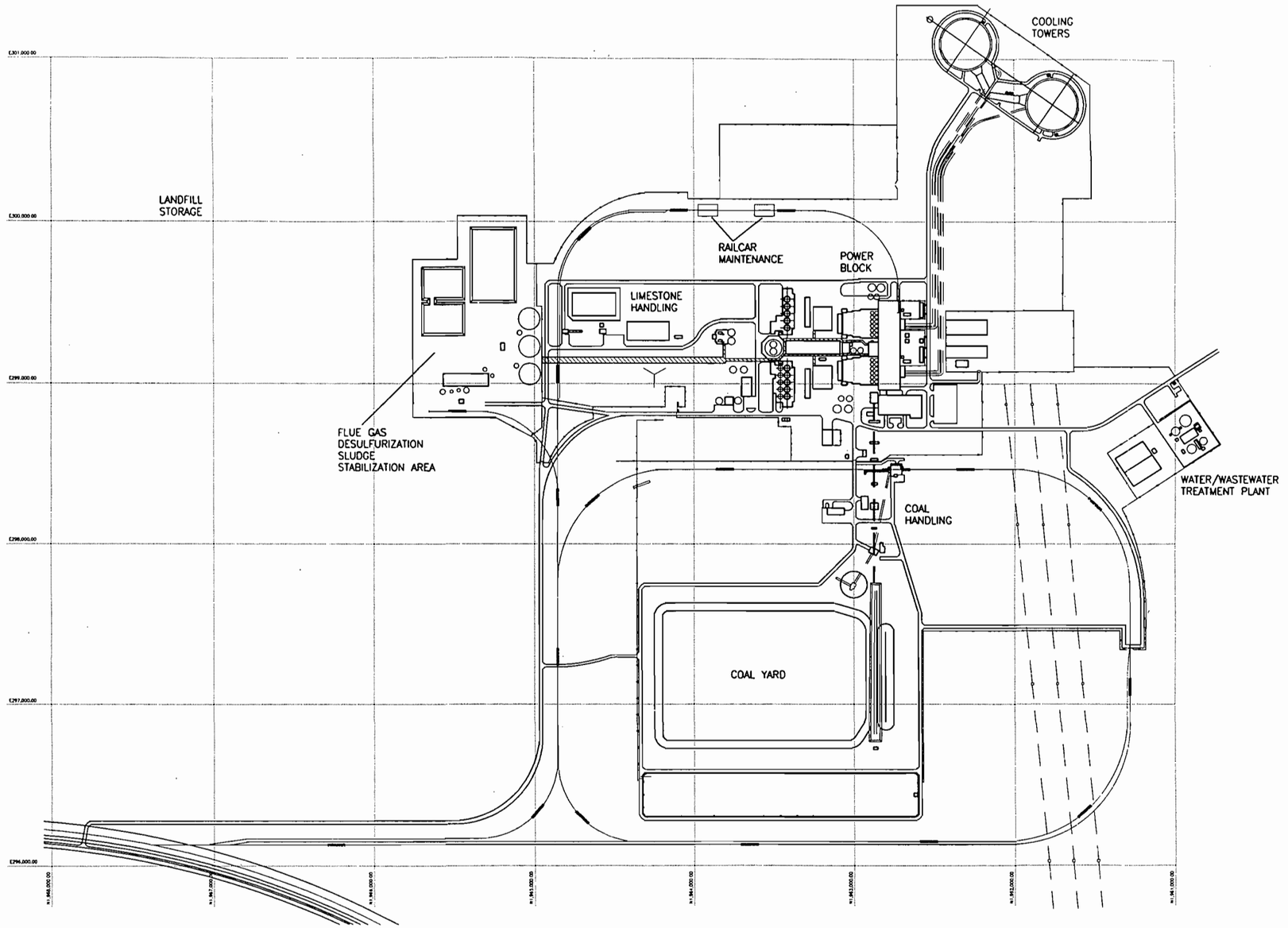

N

GRAPHIC SCALE

0 375 750

SCALE IN FEET

FIGURE II.D.2.1.

OVERALL FACILITY PLOT PLAN

Source: Seminole Electric, 1984.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

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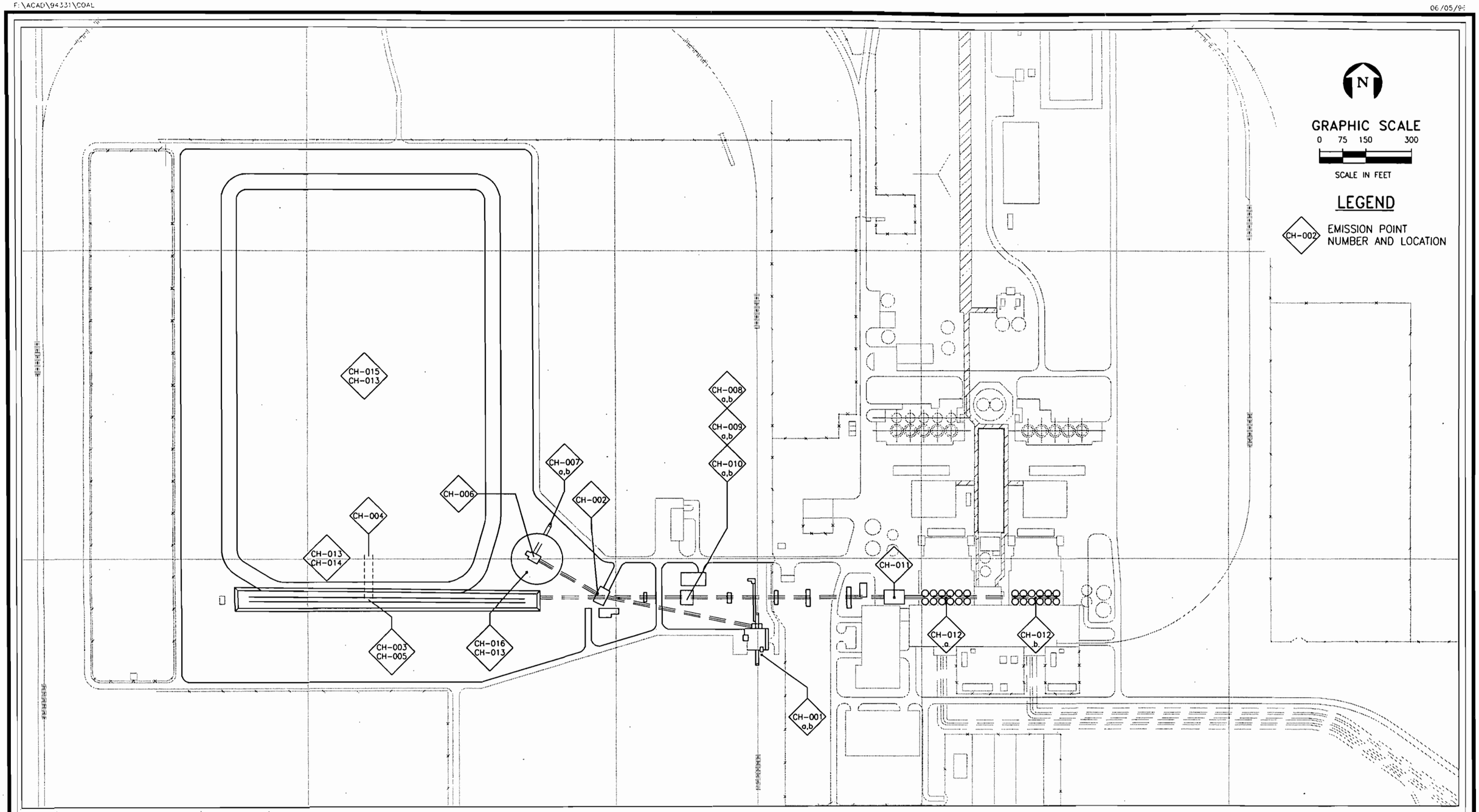

FIGURE II.D.2.2.

COAL HANDLING

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

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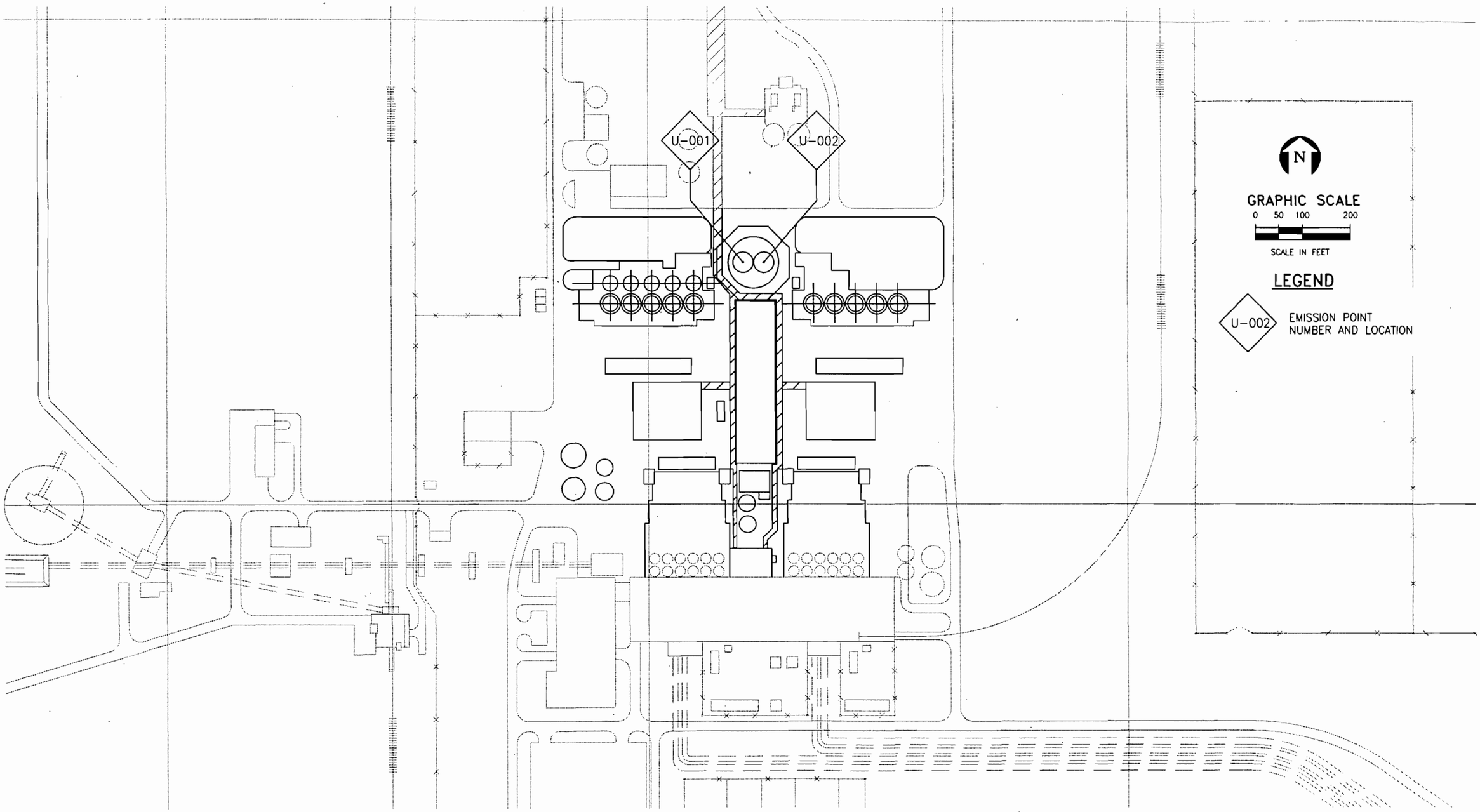

FIGURE II.D.2.3.

POWER BLOCK

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

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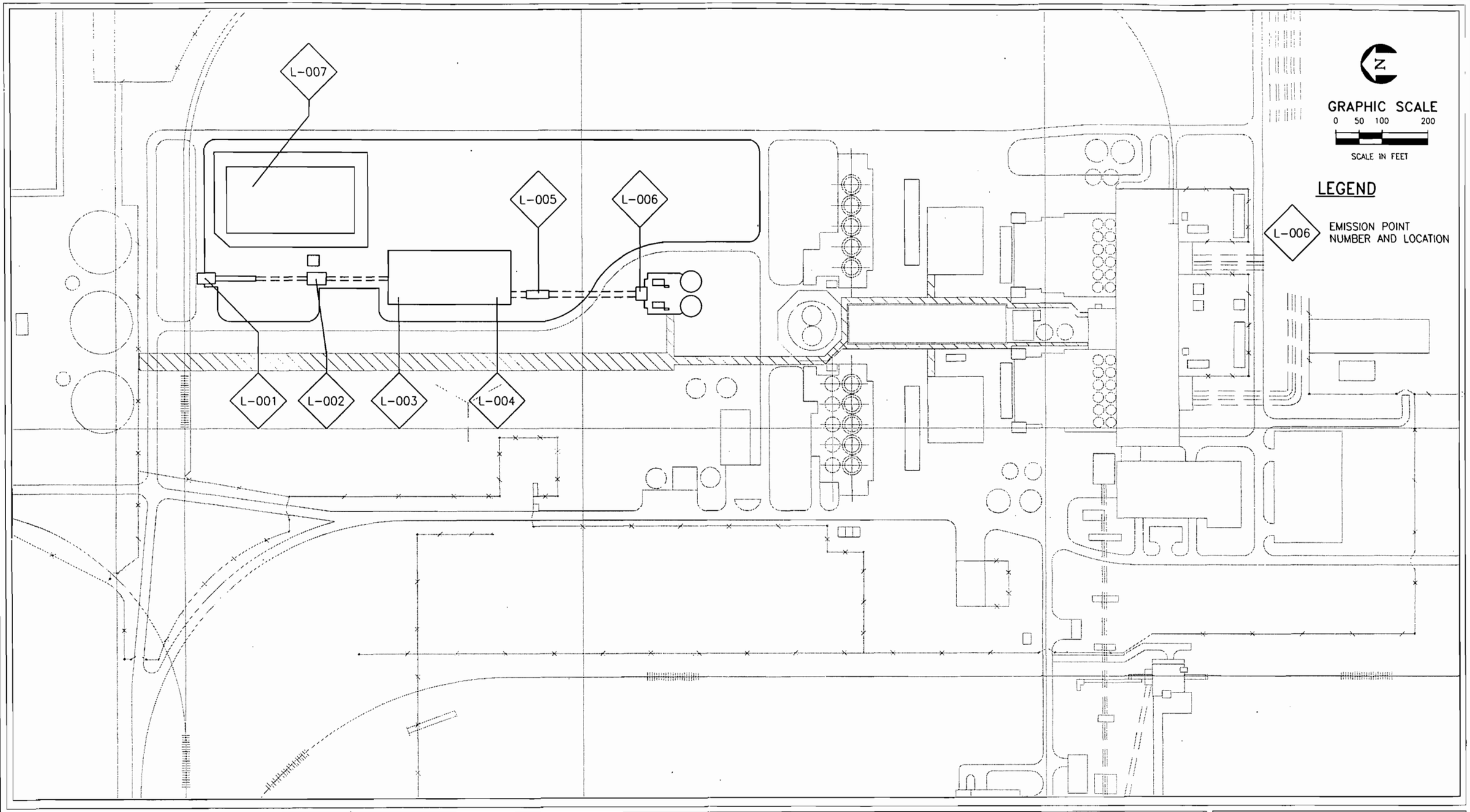

FIGURE II.D.2.4.

LIMESTONE HANDLING

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

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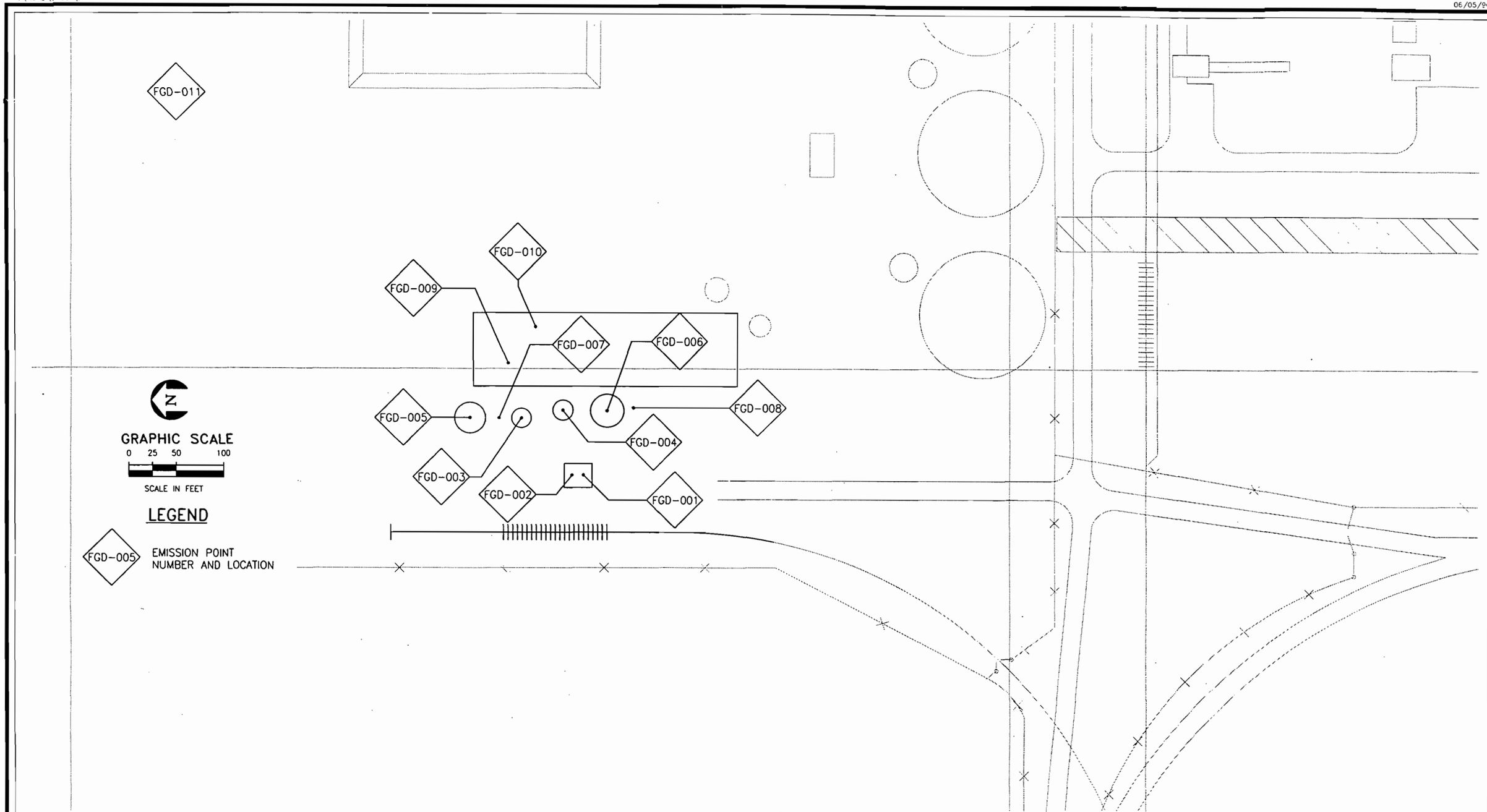

FIGURE II.D.2.5.

FLUE GAS DESULFURIZATION SLUDGE STABILIZATION AREA

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

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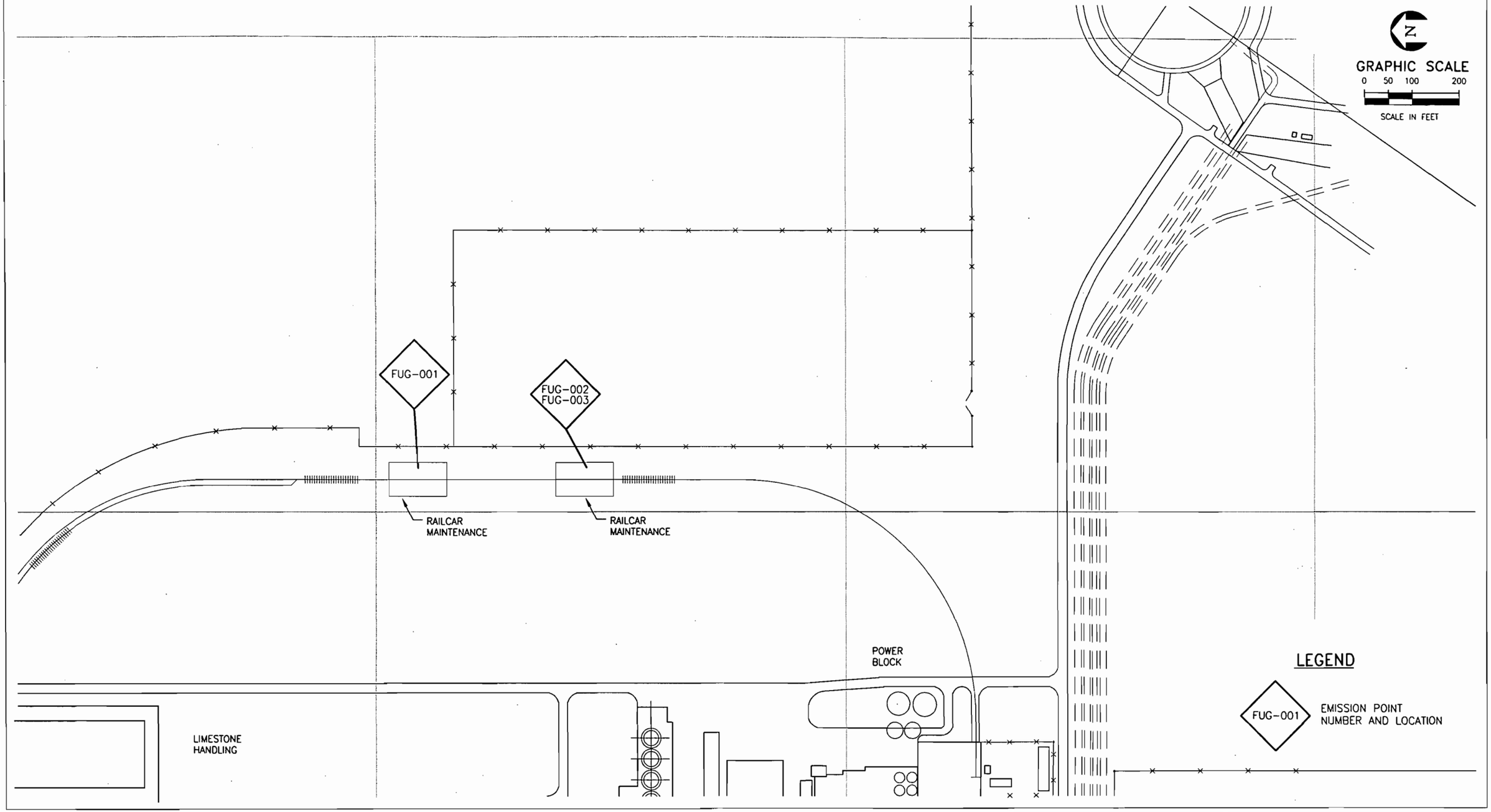


FIGURE II.D.2.6.

RAILCAR MAINTENANCE

Source: ECT, 1996.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

II.D.3

PROCESS FLOW DIAGRAMS

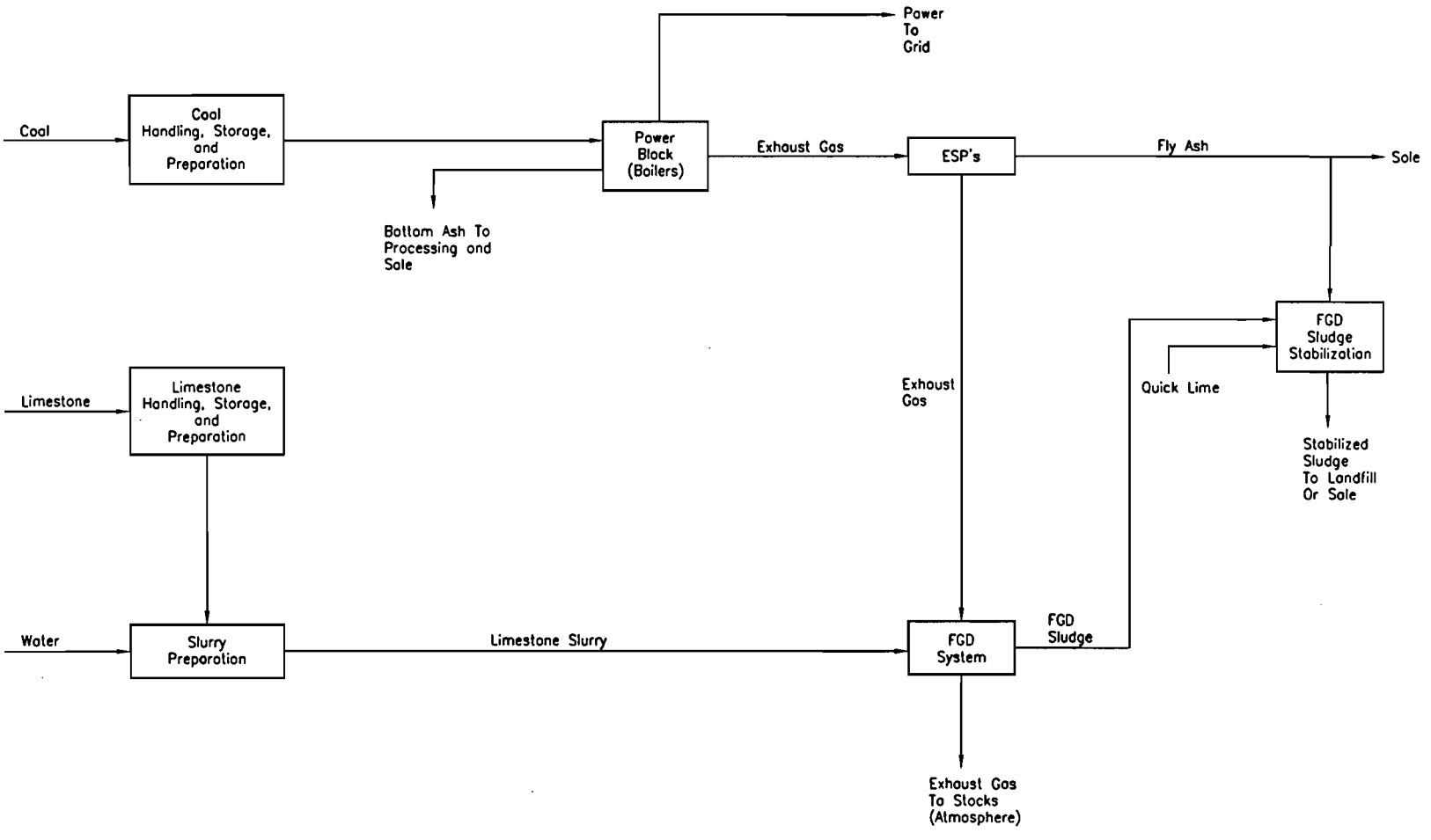


FIGURE II.D.3.1.

OVERALL FACILITY PROCESS SCHEMATIC

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

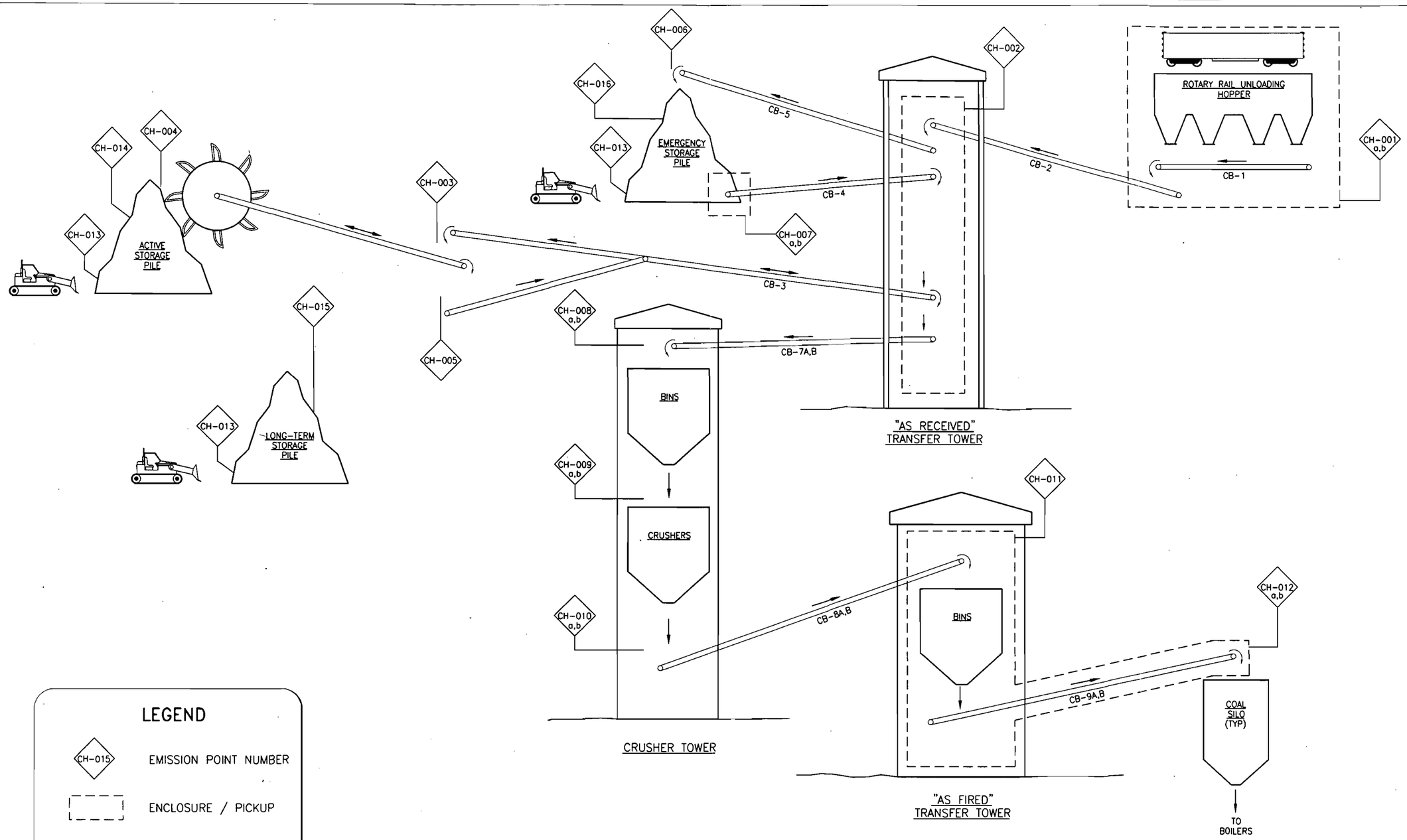


FIGURE II.D.3.2.

PROCESS FLOW SCHEMATIC: COAL HANDLING AND STORAGE

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

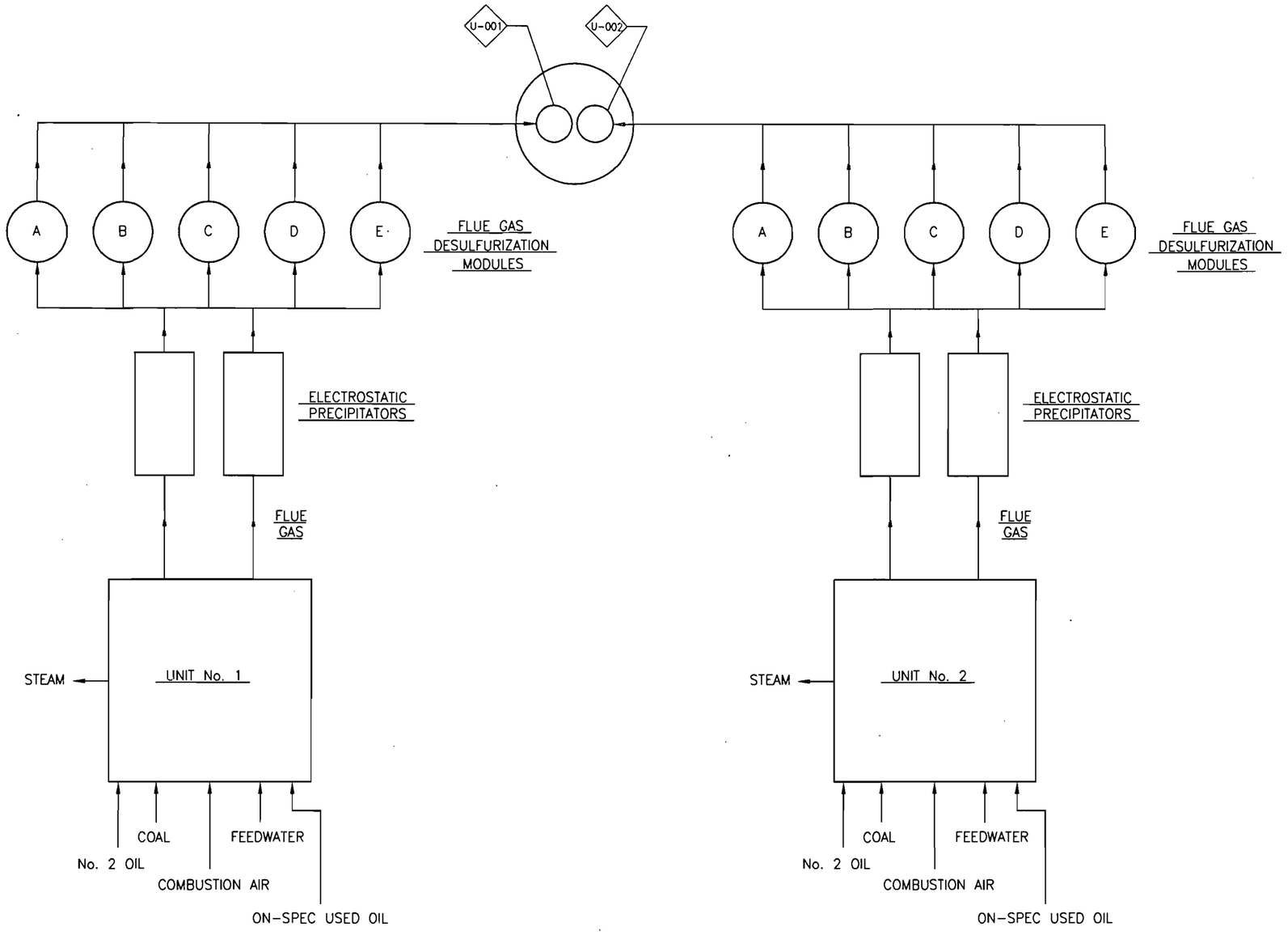
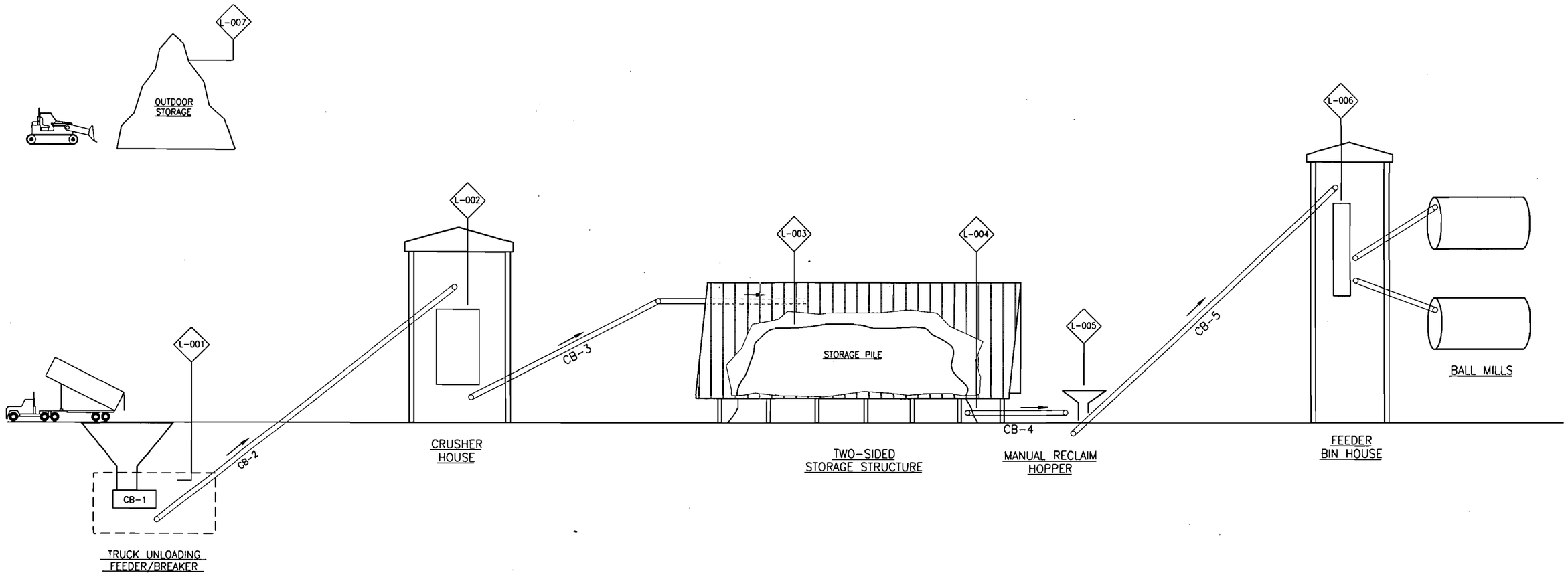


FIGURE II.D.3.3.

BOILER PROCESS FLOW DIAGRAM

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED



LEGEND

L-004 EMISSION POINT NUMBER

FIGURE II.D.3.4.

LIMESTONE HANDLING PROCESS FLOW DIAGRAM

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

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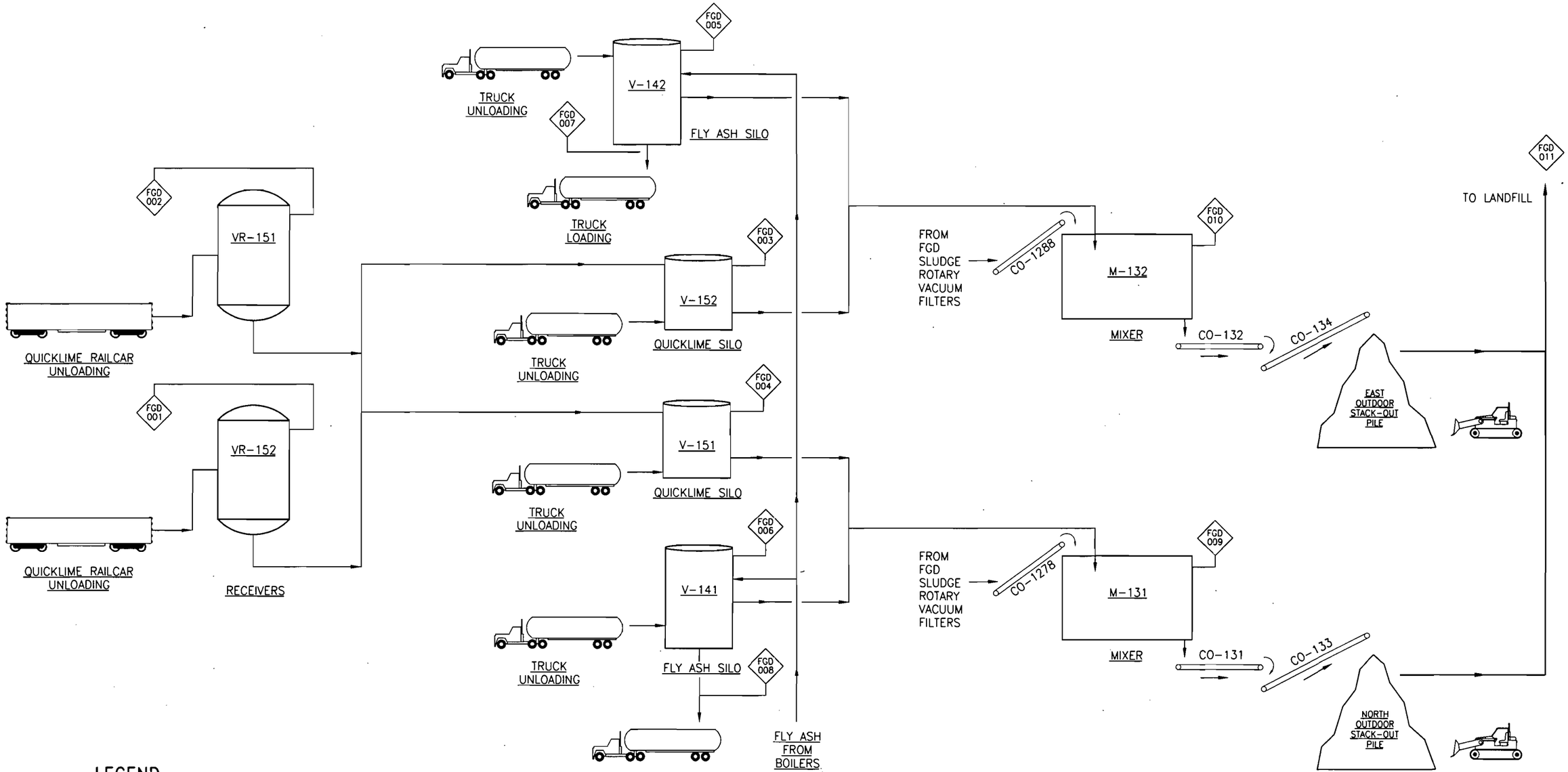

FIGURE II.D.3.5.

FGD SLUDGE STABILIZATION PROCESS FLOW DIAGRAM

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

II.D.13 & 14

COMPLIANCE REPORT, PLAN, AND CERTIFICATION

COMPLIANCE REPORT, PLAN, AND CERTIFICATION

1. Compliance Report and Plan

Appendix A to this application identifies and explains the requirements that are applicable to the emission units that comprise this Title V source. At the date of application submittal, each emissions unit is in compliance with the respective applicable requirements.

2. Proposed Schedule for the Submission of Periodic Compliance Statements Throughout the Permit Term

Periodic compliance statements are proposed to be submitted on an annual basis, from the date of permit issuance, consistent with FDEP Rule 62-213.440(3)(b), F.A.C.

3. Compliance Certification

I, the undersigned, am the responsible official as defined in Chapter 62-210.200, F.A.C., of the Title V source for which this report is being submitted. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made and data contained in this report are true, accurate, and complete.

Richard Midulla — 6/13/96

Richard Midulla
Senior Vice President, Technical Division

Date

III.I.2

FUEL ANALYSES

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 1919 SOUTH HIGHLAND AVE., SUITE 210-B, LOMBARD, ILLINOIS 60148 • TEL: 708-953-9300 FAX: 708-953-9306
SINCE 1908
Member of the SGS Group (Société Générale de Surveillance)

April 4, 1995

PLEASE ADDRESS ALL CORRESPONDENCE T
P.O. BOX 752, HENDERSON, KY 424
TEL: (502) 827-11
FAX: (502) 826-07

SEMINOLE ELECTRIC CORPORATION
P. O. BOX 272000
TAMPA FL 33688

Sample identification by
Seminole Electric

January 1995 Composite
As Fired Coal
Date Sampled: 1/1-31/95
P.O. #B9308-02815

Kind of sample reported to us: Coal

Sample taken at: -----

Sample taken by: Seminole Electric

Date sampled: January 1-31, 1995

Date received: February 13, 1995

Analysis Report No. 63-73996

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	10.68	xxxxx
% Carbon	66.04	73.94
% Hydrogen	4.63	5.18
% Nitrogen	1.23	1.38
% Sulfur	2.58	2.89
% Ash	7.95	8.90
% Oxygen(diff)	6.89	7.71
	100.00	100.00
% Chlorine	0.19	0.21

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

Manager, Henderson Laboratory

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 1919 SOUTH HIGHLAND AVE., SUITE 210-B, LOMBARD, ILLINOIS 60148 • TEL: 708-953-9300 FAX: 708-953-9306
Member of the SGS Group (Société Générale de Surveillance)

April 4, 1995

PLEASE ADDRESS ALL CORRESPONDENCE TO:
P.O. BOX 752, HENDERSON, KY 42420
TEL: (502) 827-1187
FAX: (502) 826-0719

SEMINOLE ELECTRIC CORPORATION
P. O. BOX 272000
TAMPA FL 33688

Sample identification by
Seminole Electric

January 1995 Composite
As Fired Coal
Date Sampled: 1/1-31/95
P.O. #B9308-02815

Kind of sample reported to us: Coal

Sample taken at: -----

Sample taken by: Seminole Electric

Date sampled: January 1-31, 1995

Date received: February 13, 1995

Analysis Report No. 63-73996

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	49.04
Aluminum oxide	20.33
Titanium dioxide	1.05
Iron oxide	20.23
Calcium oxide	3.00
Magnesium oxide	0.80
Potassium oxide	2.25
Sodium oxide	0.96
Sulfur trioxide	1.75
Phosphorus pentoxide	0.18
Strontium oxide	0.04
Barium oxide	0.06
Manganese oxide	0.11
Undetermined	0.20
	100.00

Silica Value = 67.11
Base:Acid Ratio = 0.39
T_{250} Temperature = 2427 °F

Type of Ash = BITUMINOUS
Fouling Index = 0.37
Slagging Index = 1.13

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

Manager, Henderson Laboratory

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Kind of sample reported to us: Coal

Sample taken at: -----

Sample taken by: Seminole Electric

Date sampled: January 1-31, 1995

Date received: February 13, 1995

Analysis report no. 63-73996

TRACE ANALYSIS

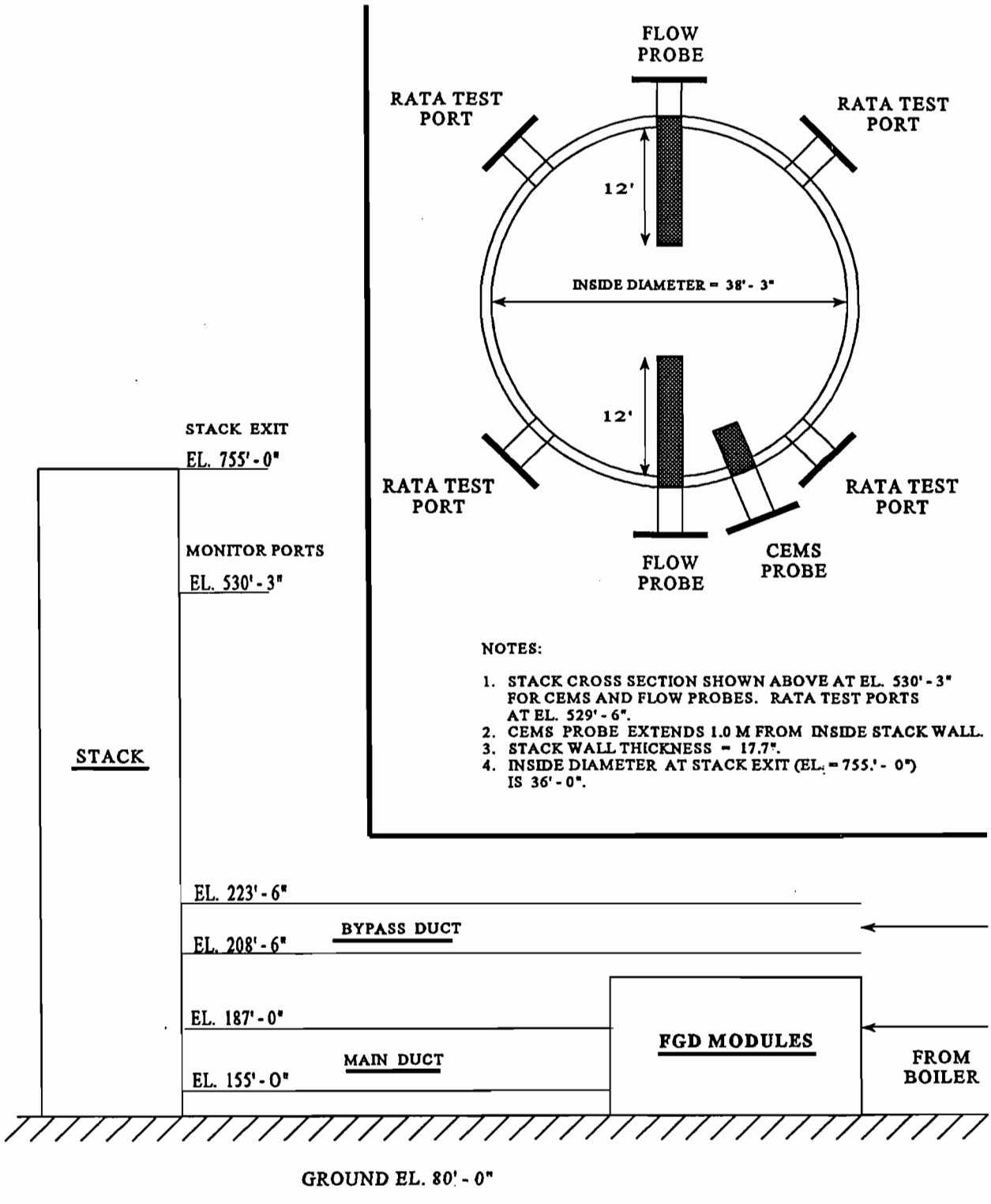
Parameter	ug/g, dry coal basis	Parameter	ug/g, dry coal basis
Antimony, Sb	<1	Molybdenum, Mo	<2
Arsenic, As	4	Nickel, Ni	8
Barium, Ba	39	Selenium, Se	3
Beryllium, Be	1.0	Silver, Ag	<0.2
Cadmium, Cd	<0.2	Strontium, Sr	28
Chloride, Cl	2500	Tin, Sn	<1
Chromium, Cr	15	Uranium, U	1.8
Cobalt, Co	3	Vanadium, V	44
Copper, Cu	7	Zinc, Zn	42
		Zirconium, Zr	15
Fluoride, Fl	70		
Lead, Pb	8		
Lithium, Li	8	Radium 226 pCi/g	0.5 +/- 0.2
Manganese, Mn	24	Radium 228 pCi/g	0.3 +/- 0.5
Mercury, Hg	0.08		

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

Manager, Henderson Laboratory

III.I.4

DESCRIPTION OF STACK SAMPLING FACILITIES



NOTES:

1. STACK CROSS SECTION SHOWN ABOVE AT EL. 530'- 3" FOR CEMS AND FLOW PROBES. RATA TEST PORTS AT EL. 529'- 6".
2. CEMS PROBE EXTENDS 1.0 M FROM INSIDE STACK WALL.
3. STACK WALL THICKNESS = 17.7".
4. INSIDE DIAMETER AT STACK EXIT (EL. = 755.'- 0") IS 36'- 0".

SEMINOLE POWER PLANT
BOILER #1 STACK AND DUCT DRAWING

Source: ECT, 1994.

ECT
Environmental Consulting & Technology, Inc.

III.I.6

PROCEDURES FOR STARTUP AND SHUTDOWN

PROCEDURES FOR STARTUP AND SHUTDOWN
SEMINOLE POWER PLANT

SECI's nonexclusive procedures for startup and shutdown are set forth in the following pages. These procedures are adjusted from time to time.

This procedure is to be followed for cold start-ups of the unit. If it is necessary to deviate from this procedure, OA-1 SHALL be followed.

CAUTION: U-2 has an ABB sliding pressure live steam pressure controller. This controller must have its set point adjusted prior to placing the unit on the line to avoid inadvertent trips from the live steam pressure controller coming into action.

_____1. Verify all necessary clearances released, ~~and vessel entry~~ confined space logs have been signed off, and jumper/lifted lead log has been reviewed and cleared of any inappropriate jumpers/lifted leads.

_____2. Verify from the condensate system checklist that the condensate system is lined up and ready for service with condensate polishers by-passed.

_____3. Verify circulating water system is in service with two pumps in operation.

_____4. Have condensate storage tank water quality checked by lab. Fill hotwell to normal level and drain to waste. If hotwell had not been drained, drain and refill to normal level. Restart condensate system.

_____ 4.1 Hot charge spare feed tank 8 bolts ammonia - valve in upstream of D.A. level control valve.

_____5. The dewatering system should be ready to receive waste slurry from the FGD and to send return supernate to the supernate tank in the FGD area.

_____ 5.1 Start the service water booster pump using the selector switch. If the required water pressure at the battery limit of the SW booster pump is available, and the manual suction and discharge valves are in the "open" position, the pump will start.

_____ 5.2 Place the waste slurry-supernate return loop in service.

_____ 5.2.1 Contact JTM to have their return pump placed in service.

_____ 5.2.2 Place the supernate pump selector switch in the "Start" position. If the low-level sensing switch (LSL 0702) is satisfied and the JTM

return tank level is adequate, the pump will start.

_____ 5.3 Reagent Slurry Loop Start-up

_____ 5.3.1 Place the reagent slurry transfer pump selector switch in the "Start" position. If the level of the reagent storage tank satisfies the low level condition, the pump will start.

_____ 5.3.2 Have the Support Systems Operator verify good return flow of reagent back to the reagent storage tank.

NOTE: Step 6 below may be omitted if D.A. has not been drained.

_____ 6. With polisher vessels by-passed, fill the D.A. to normal level with one condensate pump and the D.A. level control by-pass valve. Keep remaining condensate pumps in pull-to-lock. Shut down the condensate pump (pull-to-lock) and drain the D.A. to waste through the hotwell. Drain hotwell and refill to normal level. Restart condensate system.

_____ 7. With polisher vessels by-passed, fill D.A. to high level as in Step 5 while maintaining hotwell level. Begin the condensate loop flow through D.A. high level dump to hotwell. It may be necessary to bleed condensate to waste (hotwell drain) and make-up from condensate storage tank to lower iron oxide reading to <u>≤2000 ppb.</u> If condensate flow is stable, controls may be placed in automatic.

_____ 8. HD270 and LCV625 bypass should be opened to ensure adequate flow through D.A. flow loop. Also ensure the D.A. belly drain is open to drain any sediment. This line-up is to remain this way until unit is on bypass.

_____ 9. When condensate pump discharge iron oxide is less than 2000 ppb, specific conductivity is less than 20 mmho, and chloride is less than 1 mg/1, (verified by lab personnel) place one polisher vessel in service. Change to clean vessel as necessary.

_____ 10. Use dual point injection the whole time. (1) Too much pressure to overcome at single point with 2 condensate pumps. (2) With adequate chemistry

bypass polishers prior to filling boiler. Place one carbohydrazide pump in service and adjust feed rate with manual loader (1-HK-4039) until #3 F.W. heater discharge carbohydrazide residue is 40-100 ppb. Place one ammonia pump in service, use spare tank and adjust feed rate with manual loader (1-CCC-4038) until #3 F.W. heater discharge specific conductivity is 2.5 to 5.0 MMHO or Ph 8.5 - 9.3.

_____ 11. If available, cross tie the auxiliary steam system in order to seal the turbine and pull vacuum on condenser. This will help remove dissolved oxygen from the condensate which helps prevent iron build-up in the preboiler piping and boiler. Ensure vacuum breakers have seal water.

_____ A. Place the gland steam function group "on".

_____ B. Place lube oil and jacking oil function group "on" lube oil 70 - 100°F.

_____ C. Establish seal oil.

_____ D. Check turbine oil and EHC fluid tank levels.

_____ E. Put main turbine on turbine gear.

_____ F. Check valving for exhaust hood sprays.

_____ G. Ensure all BCC and other charts/recorders are in service.

NOTE: If cross tied this will add steam to the unit that is starting up, thus causing the hotwell level to increase. If start-up is delayed for an abnormal period, untie the units when pressure is adequate.

_____ 12. When condensate polisher effluent reading is down to 100 ppb iron oxide, the water quality is sufficient to be used in the boiler.

_____ 13. A. Check start ALL auxiliary lube oil pumps, I.D., F.D., P.A., ball mills, etc.

_____ B. Check for any problems.

_____ C. Leave either all "A" or all "B" pumps in service.

_____ D. Place B.F.P.'s on T.G. and open HMV-1301 bypass valve.

_____ E. Exercise all BSO dampers.

_____ 14. Verify the "pre-fire" requirements are completed by the control room, unit and auxiliary operator, checklists (Attachments 1, 2, 3 and 4).

_____ 15. When adequate vacuum is achieved, reset main turbine and L.P. bypass. (To locate any problems)

_____ 16. Open bypass on polisher to allow more chemicals to boiler. Contact laboratory personnel prior to filling boiler. Have lab verify proper concentration of ammonia and carbohydrazide as boiler is filled. (Ph 8.5 - 9.3, conductivity 2.5 - 5.0 umho carbohydrazide 40 - 100 ppg). Fill the boiler using the boiler fill line off of the condensate pump discharge header to 5 ports. Verify locally at drum and compare with control room indication. Drain drum level back down (3 ports) for firing and verify level locally at drum. Have lab check iron level, at water wall drains, should be (<2000 ppb).

_____ 17. Start air preheaters, and open secondary air inlet and outlet and gas inlet and outlet dampers.

_____ 18. Verify clear path for air flow from fans to stack utilizing the FGD system bypass.

_____ 19. Place one ID fan in service and one FD fan in service maintaining furnace draft at -1/3". Place in service ID fan in "AUTO".

_____ 20. Place second ID fan in service and second FD fan in service maintaining furnace draft at -1/2". Parallel in service ID fans and place the second ID fan in "AUTO".

NOTE: If problems are encountered in starting the second ID or FD, do not delay startup. Proceed with the startup sequence while attempting to start the second set of fans. One set of fans is adequate to initially fire boiler and synchronize generator. Normally, #1 or #2 ID is started with #1 FD and #3 or #4 ID is started with #2FD. This is for even flow through precipitators.

_____ 21. Parallel FD fans and raise air flow to 2.2 million LB/hr. Verify the airflow MFT signal and air flow <30% alarm clear as airflow is increased.

_____ 22. Start tertiary air fans and a scanner fan. Place redundant fans in standby.

_____ 23. Place boiler thermoprobes in service. If available.

NOTE: Contact lab personnel when ready to light off ignitors.

_____ 24. Start one ignition oil pump and operate main steam lead drains in accordance with handout dated 4/2/86 by Operations Superintendent. See operation instruction book. Lab will sample every two hours.

_____ 25. Select "BYPASS" mode on turbomat prior to boiler purge.

_____ 26. Depress the purge start button on the Forney panel. If all permissives are met the 5 minute purge will begin. Purge permissives are:

_____ A. Air heaters in service.

_____ B. FD & ID fans in service.

_____ C. All mills and feeders stopped.

_____ D. All burner shut-off dampers closed.

_____ E. Ignitor trip valve closed.

_____ F. No primary air fan running.

_____ G. No flame detected.

_____ H. 80% burner air registers to light off position.

_____ I. Both reheat and economizer pass dampers open.

_____ J. Full air flow path established.

_____ K. Tertiary air fans in service.

_____ L. All precipitators tripped.

_____ M. All ignition oil valves closed.

_____ N. All P.A.S.O. dampers closed.

_____ O. Furnace pressure in limits.

_____ P. All auxiliary air dampers closed.

_____ Q. All S.A.S.O. dampers closed.

_____ R. No boiler trip cond. present.

_____ S. Precipitator seal air fans running.

_____ T. Primary air dampers closed.

_____ U. Scanner cooling fan running.

_____ V. Air flow > 25% < 40%.

CAUTION: Station an operator on the lower burner decks to check for oil leaks before opening ignitor trip valve.

_____ 27. When purge is complete open the ignitor trip valve. When oil pressure is stabilized, place ignitors in service associated with mills 5 and 6. This operation SHALL be observed locally so that visual observation of flames may occur. The local operator SHALL monitor ignitor fires and make adjustments as necessary to reduce smoke from oil guns and optimize opacity until 2 pulverizers are in service.

_____ A. MFT and IFT relays reset when the ignitor trip valve opens.

_____ B. Maintain drum level within limits and air flow above 25%.

_____ 28. Close R.H. damper to approximately 25%, since there is no flow yet in the R.H. section.

_____ 29. Open the continuous blowdown 100% and use the boiler fill line from the condensate discharge header to maintain drum level in limits. If proper firing rate is held and blowdown controlled, -5" in drum is enough water, due to swelling, so as not to need to add water to boiler until 350 psi, so as to utilize #3 B.F.P.

_____ 30. Line up dampers and auxiliary equipment and start the primary air fans. Do not load fans at this time. Load when placing ball mills in service.

_____ 31. Verify three air compressors in service. Start the

air heater blowing sequence using steam as the blowing medium, if the aux steam is cross tied. If not, use compressed air.

_____ 32. Firing rate must be controlled so as not to exceed 200°F between top and bottom drum metal temperature and 1000°F gas temperature on thermoprobes. The pass dampers will allow some flexibility in controlling temperatures. Computer points for drum metal temps are: Unit 1 BT1007 through BT 1016, AT^5 BC1003 through BC1007, Unit 2 BT2007 through BT2016, AT^5 BC2003 through BC2007.

_____ 33. Jog down #7 F.W. heater outlet valve to approximately 5% open, and open #7 heater extraction M.O.V. from cold reheat 100%. This is to help preheat feedwater and minimize L.P. bypass flow into the condenser (efficiency). If unable to jog down #7 F.W. heater, then jog down #8 F.W. heater outlet M.O.V. Jogging down is to assure S.H. sprays, when necessary. If #8 is jogged down, still have #7 in service.

_____ 34. If units were not cross tied on auxiliary steam system, then open the auxiliary steam supply valve to allow the auxiliary steam line to warm up with the boiler and to prevent a drum level excursion if opened later.

_____ 35. Open the pegging steam valve to the D.A.

_____ 36. When 25 lbs. drum pressure is attained close the drum and superheater vents. Verify the "25 PSI drum pressure requirements" have been completed per the control room, unit and auxiliary operator boiler checklist (Attachments 1, 2 and 3). Add ignitors to increase firing rate up to the limit for T on steam drum, or 1000°F probe limit.

_____ 37. At approximately 150 PSI drum pressure the drum level will start to rise (swell). It may be necessary to utilize the mass blowdown to maintain drum level within limits. Firing rate can also be manipulated to control this.

_____ 38. When 250 PSI drum pressure is attained, place the No. 3 boiler feed pump in service and close the condensate boiler fill valve. The mass blowdown should be opened to 50% at this time, and remain there, until turbine by-pass operation for

sufficient flow to control drum level. If adequate drum level control is attained the No. 3 boiler feed pump may be placed on automatic. If a T.D.B.F.P. is used, operate with recirc. 100% open in manual until pump is working hard enough to keep turbine exhaust from overheating. Drum pressure might need to be higher if a T.D.B.F.P. is utilized.

_____ 39. If boiler drum blowdown Ph (1-XR-4042) is between 8.3 and 9.2, iron oxide is less than 200 ppb, and specific conductivity (1-CJR-40441) is between 2.5 and 3.5 mmho, continue increasing drum pressure as required. Lab personnel should provide hourly readings.

_____ 40. Condensate flow should be sufficient to place the DA level control valve on automatic as well as hotwell make-up valves.

_____ 41. If boiler drum blowdown pH (1-XR-4042) is below 8.3, iron oxide is greater than 200 ppb, or specific conductivity (1-CJR-4041) is greater than 3.5 mmho due to ionic contamination, alternately open and close the boiler bottom drains for 30 seconds on each valve (not to exceed drum level limitations) between 400 PSI and 800 PSI drum pressure.

CAUTION: DO NOT BLOWDOWN USING BOILER BOTTOM DRAINS WHEN PRESSURE IS OVER 800 PSI.

_____ 42. Keep continuous boiler drum blowdown valve 100% open until water quality permits reduced blowdown rate. Mass blowdown is to be closed when unit is stable on bypass, unless water quality/lab deems it necessary to do otherwise.

_____ 43. If vacuum was not pulled earlier, place the turbine gland steam function group in the "ON" position. This will open the drain on the gland steam header and start the warm-up period. Gland steam function group can be placed in stop-manual, and open drain manually also.

_____ 44. As soon as the temperature is adequate for the gland steam function group (superheat >90°F and aux. steam >446°F) the supply valve will open.

_____ 45. Ensure vacuum breakers are closed and have seal

water on them, then start two vacuum pumps to establish vacuum.

_____ 46. When vacuum is established, reset the LP bypass system. Verify the LP stop valves open (7" to 5" Hg). Check that LP bypass spray water is valved in. Should not reset without adequate spray water. Also reset the main turbine and verify the HP and IP stop valves open.

_____ 47. Initiate a pre-bypass checklist and reset H.P. bypass, if tripped.

_____ 48. At 400 psi start pressurizing and warming the electromatic power relief valves by slowly opening the bypass valves on both isolation valves. The relief valves must be warmed for at least 30 minutes prior to operating.

At 500 psi have the electromatics valved in. Then test them one at a time approximately 5 to 10 seconds. Be prepared for a sharp increase in drum level when this is done.

_____ 49. P.A. fans will need to be loaded at this time. Have the first mill in service when boiler pressure reaches 500 psig. Verify there is no coal laying cut in burners. Start one of the lower ball mills.

_____ 50. Just prior to opening the Paso on the first mill, open the H.P. bypass 10% manually. Control Hp bypass discharge temperature at 650°F. Open the Paso on the in-service mill and start the coal feeders. Establish and maintain normal mill level and temperature. Retract thermal probes if in service. Continue to monitor and control steam drum T. Fire mill lightly until 600 psi is achieved (M.S.). Ensure H.P. warm-up valves open 100%.

NOTE: **Opening of HP bypass valves will cause drum level to go high if opened too much. Do not close the HP bypass valves while on manual control or a MFT will occur.**

_____ 51. Notify Support Systems operators to place electrostatic precipitators in service when coal fire is visually verified in the furnace.

_____ 52. Increase firing rate (not to exceed limitations in step 31) and increase opening of HP bypass valves

to increase steam flow while allowing pressure to slowly increase as well.

_____ 53. When coal fires are established it is necessary to utilize the superheat sprays to control main steam temperature at or below 750°F.

_____ 54. When boiler pressure reaches 1200 PSI the HP bypass should be approximately 50% open (480,000 to 500,000 lb./hr.).

_____ 55. Set the HP bypass setpoint at 1200 PSI and place the HP bypass valves on automatic.

_____ 56. Place the reheat and superheat pass dampers on automatic with R.H. setpoint at 700°F (115 psi @ 700°F = 361.92° Sh).

_____ 57. Verify the "10% steam flow" requirements have been completed per the control room, unit and auxiliary operators boiler checklists (Attachments 1, 2, 3 and 4).

_____ 58. Place the second bottom elevation coal mill in service with 4 burners in service after purging coal conduits. If lower mill is unavailable, mills 2 or 4 can be utilized.

NOTE: This may cause drum level to swell rapidly. Use method as noted in Step 49. Have the absorber liquid side on three (3) modules in service.

_____ 59. Increase firing rate until thermal megawatts are approximately 130 as indicated on the L&N master panel.

NOTE: Steam flow should then be greater than 10% and the HP bypass approximately 90% open.

_____ 60. Increase firing rate until:

_____ A. Thermal megawatts approx. 130 MW.

_____ B. Throttle pressure approx. 1200.

_____ C. Main steam temperature 750°, R.H. temperature @ 700°F.

_____ D. HP bypass open approx. 90% to 100%.

_____ E. All conditions under control.

_____ F. Boiler/manual control mode.

_____ 61. All F.W. controls should/could be in auto at this time.

_____ 62. When the O_2 is below 10%, the scrubber modules should be put into service by notifying the Support Systems Control Room Operator.

_____ 63. Verify all turbine drains open, oil temperature 85 to 110°F, > 40 PSI header pressure, and stator cooling system in service, and generator H_2 pressure at 65 lbs. minimum.

_____ 64. Select "IDLE" mode on the turbomat panel. (Turbine should have been on turning gear at least 4 hours prior to rolling.) Main steam temperature may have to be increased to provide permissive to roll turbine.

_____ 65. Roll the turbine up to 500 RPM and hold for approximately 20 minutes. Check the turbine/generator for rubbing, vibration, oil flow, etc.

_____ 66. Roll the turbine up to 1200 RPM and hold for approximately 20 minutes checking the turbine/generator conditions as above. (Check that turning gear motor has stopped > 800 RPM.) Hold at 1200 RPM until HP probe shows a decreasing trend. Begin procedure for starting next (3rd) mill (2 or 4). 3rd mill should be available for service just before synchronization.

_____ 67. Roll the turbine up to 3600 RPM. The control system will roll the turbine up at a rate allowed by the HP and IP probes. 30/min. Check all turbine/generator supervisory instrumentation as well as local checks.

NOTE: **Roll time will be approximately 2 hours from initial roll to rated speed. When 3600 RPM's is reached, notify dispatcher of intentions to synch. and tie.**

_____ 68. When the turbine reaches 3600 RPM select "LOAD" mode on turbomat, close the generator field breaker. Observe that generator terminal voltage increases, and is matched with grid voltage.

NOTE: If load mode is selected early the synchronization mode times out (640 seconds) before the Unit can tie on in the auto mode. Load mode should be selected when ready to tie-on.

When the turbine is synchronized, or sooner under certain conditions, the FGD Control Room Operator should begin placing modules in service by opening the selected module's inlet isolation damper first. Once it is open, the outlet isolation damper should be opened to place the module in service. Three modules in service. Close bypass isolation damper. Log closed on DP 30.

_____ 69. Set the target load at 100 MWS and the load gradient at 25 MWS/MIN.

_____ 70. Remove one of the switches for the generator OCB's (either 8W30 or 8/W40) from the pull-to-lock position to the green flag position (normal after trip position).

_____ 71. Unlock the sync. switch for the corresponding breaker taken out of pull-to-lock in step #69. Turn the spring loaded sync. switch all the way to the "auto on" position and let it return to the "auto" position. The "auto" sync. circuit should automatically adjust the generator voltage to match the line voltage on the grid and the frequency. <u>THIS IS TO BE VERIFIED.</u> The selected OCB will not auto close in the "GREEN FLAG" position (normal after trip position). When frequency and voltage are matched, as the sync. scope is moving in the clockwise direction the selected OCB control switch is to be placed in the "RED FLAG" position <u>only</u> when the sync. scope is between the 10 o'clock and 12 o'clock position. If the OCB doesn't auto close between 10 o'clock and 12 o'clock it is to be placed back in the "GREEN FLAG" position until the sync. scope is moving clockwise and between 10 o'clock and 12 o'clock. Verify a breaker close signal is being sent by observing the synchronization red lamp illuminates in pulse fashion when the synchroscope pointer is between the 10 o'clock and 12 o'clock position. The OCB control switch should <u>never</u> be in the "RED FLAG" position unless these conditions exist or the OCB is close in. Upon synchronization, zero var's. (Do not totally depend on automatic mode!) If unable to sync. in auto take the sync. switch for the corresponding breaker taken out of pull-to-lock in step 69, and turn the sync. switch to manual.

Use the frequent controller to adjust cycles so that the sync. scope starts slowly turning in a clockwise direction. Re-verify that generator voltage and grid voltage are still matched. When the sync. scope indication is at 11 o'clock and approaching 12 o'clock, close the pre-selected OCB. Zero VAR's.

_____ 72. Verify unit load comes up to the target load set value that was set in step #68.

_____ 73. Place F.W. heaters 1-6 and #8 in service. Place steam driven B.F.P. in service, if #3 B.F.P. is in service.

_____ 74. Turn the selected sync. switch off. Unlock the other sync. switch and close the corresponding generator breaker.

_____ 75. At this point the IP probe will probably be limiting. With condition most of the steam will be by-passing the IP and LP turbines. The firing rate will be higher than normal at this low load. The HP bypass must remain in "AUTO" and in service during this time.

_____ 76. If the bypass is closing to a point of closing off it may be necessary to increase the firing rate. This is accomplished by manually raising the air flow and fuel flow.

Additional recycle pumps shall be placed in service as needed when load and system DP indicate place 4th module in service.

When the IP probe is no longer limiting start picking up load using the target load set value on the turbotrol panel. Set the load gradient at 5 MWS/MIN. Load increases should be approximately 25 MW intervals.

_____ 77. Close boiler and turbine drains. Downstream valves first, then all root valves.

NOTE: **Do not select turbine follow mode if the HP bypass is still open.**

_____ 78. Continue increasing firing rate and load slowly, keeping H.P. bypass approximately 25% open for pressure control. Increase pressure as allowed by lab.

_____ 79. Transfer station service when load is > 200 mw.

_____ 80. When unit is stable at 250 MW, increase the target load set value, slightly, which will cause the H.P. bypass to close slowly. (Note: The H.P. bypass setpoint will have to be increased to a higher setpoint, than throttle pressure setpoint, to prevent H.P. bypass from opening unnecessarily.) Re-correct target load set value, or firing rate to re-stabilize unit. Unit still in boiler manual/turbine base, TT42, @ 250 MW. Match throttle pressure control setpoint with actual pressure, and select turbine follow mode only. Boiler base should only be selected after feedwater temperature is constant.

_____ 81. When unit is stabilized at 2200 PSI throttle pressure (HP bypass setpoint at 2425 PSI) raise unit load to 300 MWS while pacing another mill in service to accommodate the needed firing rate.

NOTE: Throttle pressure kept down to 2200 to ensure the L.P. bypass will not come into service.

_____ 82. When unit is at 300 MWS it will be necessary to place the other boiler feed pump turbine in service. Once the second pump is in service the loading should be approximately equal and the second pump placed on automatic.

NOTE: The second pump should be brought into service slowly allowing the already in service pump to decrease automatically while maintaining drum level.

_____ 83. At 300 MWS all essential equipment should be in service to allow unit load capability throughout the entire load range. Equipment that is not required at this time should be in a "ready for service" type of condition. Also, throttle pressure can be increased to 2400 PSI if chemistry allows.

_____ 84. The generator hydrogen pressure should be at the 75 lb. maximum pressure.

_____ 85. Notify the dispatcher the unit is available for system load requirements within the 300 to 650 MW range.

NOTE: Any known restrictions that would prevent the unit from attaining full load (650 MWS) capability should be reported to the dispatcher at this time, or earlier, and logged on the derate information form.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

Issue Date 5/7/96 | Page 1 of 11

Approved By W J Hartz | Number EO-2A R4

Subject

UNIT COLD START-UP WITH HP BY-PASS UNAVAILABLE

Section

EQUIPMENT OPERATION PROCEDURE

This procedure is to be followed for cold start-ups of the unit with unavailable HP bypass. At each step indicate the time/date/initials when each task is completed. If a task is not necessary or cannot be met indicate so. If it is necessary to deviate from this procedure, OA-1 SHALL be followed.

CAUTION: U-2 has an ABB sliding pressure live steam pressure controller. This controller must have its set point adjusted prior to placing the unit on the line to avoid inadvertent trips from the live steam pressure controller coming into action.

_____ 1. Verify all necessary clearances released, ~~and vessel entry~~ confined space logs have been signed off, and jumper/lifted lead log has been reviewed and cleared of inappropriate jumper/lifted leads.

_____ 2. Verify from the condensate system checklist that the condensate system is lined up and ready for service with condensate polishers by-passed.

_____ 3. Verify circulating water system is in service with two pumps in operation.

_____ 4. Have condensate storage tank water quality checked by lab. Fill hotwell to normal level and drain to waste. If hotwell had not been drained, drain and refill to normal level. Restart condensate system.

4.1 Hot charge spare feed tank 8 bolts ammonia - valve in upstream of D.A. level control valve.

5. The dewatering system should be ready to receive waste slurry from the FGD and to send return supernate to the supernate tank in the FGD area.

_____ 5.1 Start the service water booster pump using the selector switch. If the required water pressure at the battery limit of the SW booster pump is available, and the manual suction and discharge valves are in the "open" position, the pump will start.

_____ 5.2 Place the waste slurry-supernate return loop in service.

_____ 5.2.1 Contact JTM to have their return pump placed in service.

_____ 5.2.2 Place the supernate pump selector switch in the "Start" position. If the low-level sensing switch (LSL 0702) is satisfied and the JTM return tank level is adequate, the pump will start.

_____ 5.3 Reagent Slurry Loop Start-Up

_____ 5.3.1 Place the reagent slurry transfer pump selector switch in the "Start" position. If the level of the reagent storage tank satisfies the low level condition, the pump will start.

_____ 5.3.2 Have the Support Systems Operator verify good

return flow of reagent back to the reagent storage tank.

NOTE: Step 6 below may be omitted if D.A. has not been drained.

_____ 6. With polisher vessels by-passed, fill the D.A. to normal level with one condensate pump and the D.A. level control by-pass valve. Keep remaining condensate pumps in pull-to-lock. Shut down the condensate pump (pull-to-lock) and drain the D.A. to waste through the hotwell. Drain hotwell and refill to normal level. Restart condensate system.

_____ 7. With polisher vessels by-passed, fill D.A. to high level as in Step 5 while maintaining hotwell level. Begin the condensate loop flow through D.A. high level dump to hotwell. It may be necessary to bleed condensate to waste (hotwell drain) and make-up from condensate storage tank to lower iron oxide reading to <u><2000 ppb</u>. If condensate flow is stable, controls may be placed in automatic.

_____ 8. HD270 and LCV625 bypass should be opened to ensure adequate flow through D.A. flow loop. Also ensure the D.A. belly drain is open to drain any sediment. This line-up is to remain this way until the turbine is rolled off.

_____ 9. When condensate pump discharge iron oxide is less than 2000 ppb, specific conductivity is less than 20 mmho, and chloride is less than 1 mg/l, (verified by lab personnel) place one polisher vessel in service. Change to clean vessel as necessary.

_____ 10. Use dual point injection downstream of DA LCV the whole time. (1) Too much pressure to overcome at single point with 2 condensate pumps. (2) With adequate chemistry bypass polishers prior to filling boiler. Place one carbohydrazide pump in service and adjust feed rate with manual loader (1-HK-4039) until #3 F.W. heater discharge carbohydrazide residue is 40 - 100 ppb. Place one ammonia pump in service, use spare tank and adjust feed rate with manual loader (1-CCC-4038) until #3 F.W. heater discharge specific conductivity is 2.5 to 5.0 MMHO or Ph 8.5 - 9.3.

_____ 11. If available, cross tie the auxiliary steam system in order to seal the turbine and pull vacuum on condenser. This will help remove dissolved oxygen from the condensate which helps prevent iron build-up in the pre-boiler piping and boiler. Ensure vacuum breakers have seal water.

_____ A. Place the gland steam function group <u>"on"</u>.

_____ B. Place lube oil and jacking oil function group <u>"on"</u> lube

oil 70 - 100°F.

C. Establish seal oil.
D. Check turbine oil and EHC fluid tank levels.
E. Put main turbine on turbine gear.
F. Check valving for exhaust hood sprays.
G. Ensure all BCC and other charts/recorders are in service.

NOTE: If cross tied this will add steam to the unit that is starting up, thus causing the hotwell level to increase. If start-up is delayed for an abnormal period, untie the units when pressure is adequate.

12. When condensate polisher effluent reading is down to 100 ppb iron oxide, the water quality is sufficient to be used in the boiler.

13. A. Check start ALL auxiliary lube oil pumps, I.D., F.D., P.A., ball mills, etc.
B. Check for any problems.
C. Leave either all "A" or all "B" pumps in service.
D. Place B.F.P.'s on T.G. and open HMV-1301 bypass valve.
E. Exercise all BSO dampers.

14. Verify the "pre-fire" requirements are completed by the control room, unit and auxiliary operator, checklists (Attachments 1, 2, 3 and 4)

15. When adequate vacuum is achieved, reset main turbine.

16. Open bypass on polisher to allow more chemicals to boiler. Contact laboratory personnel prior to filling boiler. Have lab verify proper concentration of ammonia and carbohydrazide as boiler is filled. (pH 8.5 - 9.3, conductivity 2.5 - 5.0 umho carbohydrazide 40 - 100 ppg). Fill the boiler using the boiler fill line off of the condensate pump discharge header to 5 ports. Verify locally at drum and compare with control room indication. Drain drum level back down (3 ports) for firing and verify level locally at drum. Have lab check iron level, at water wall drains, should be (<2000 ppb).

17. Start air preheaters, and open secondary air inlet and outlet and gas inlet and outlet dampers.

18. Verify clear path for air flow from fans to stack utilizing the FGD system by-pass.

19. Place one ID fan in service and one FD fan in service maintaining furnace draft at -1/3". Place in service ID fan in "AUTO".

_____ 20. Place second ID fan in service and second FD fan in service. Parallel in service ID fans and place the second ID fan in "AUTO".

NOTE: If problems are encountered in starting the second ID or FD, do not delay startup. Proceed with the startup sequence while attempting to start the second set of fans. One set of fans is adequate to initially fire boiler and synchronize generator. Normally, #1 or #2 ID is started with #1 FD and #3 or #4 ID is started with #2 FD. This is for even flow through precipitators.

_____ 21. Parallel FD fans and raise air flow to 2.2 million LB/hr. Verify the airflow MFT signal and air flow <30% alarm clear as airflow is increased.

_____ 22. Start tertiary air fans and a scanner fan. Place redundant fans in standby.

_____ 23. Place boiler thermoprobes in service. If available.

NOTE: Contact lab personnel when ready to light off ignitors.

_____ 24. Start one ignition oil pump and open main steam lead drains.

_____ 25. Select "IDLE" mode on turbomat prior to boiler purge.

_____ 26. Depress the purge start button on the Forney panel. If all permissives are met the 5 minute purge will begin. Purge permissives are:

_____ A. Air heaters in service
_____ B. FD & ID fans in service
_____ C. All mills and feeders stopped
_____ D. All burner shut-off dampers closed
_____ E. Ignitor trip valve closed
_____ F. No primary air fan running
_____ G. No flame detected
_____ H. 80% burner air registers to light off position
_____ I. Both reheat and economizer pass dampers open
_____ J. Full air flow path established
_____ K. Tertiary air fans in service
_____ L. All precipitators tripped
_____ M. All ignition oil valves closed
_____ N. All P.A.S.O. dampers closed
_____ O. Furnace pressure in limits
_____ P. All auxiliary air dampers closed
_____ Q. All S.A.S.O. dampers closed
_____ R. No boiler trip cond. present
_____ S. Precipitator seal air fans running
_____ T. Primary air dampers closed

_____ U. Scanner cooling fan running
_____ V. Air flow >25% <40%

CAUTION: Station an operator on the lower burner decks to check for oil leaks before opening ignitor trip valve.

_____ 27. When purge is complete open the ignitor trip valve. When oil pressure is stabilized, place ignitors in service associated with mills 5 and 6 This operation SHALL be observed locally so that visual observation of flames may occur. The local operator SHALL monitor ignitor fires and make adjustments as necessary to reduce smoke from oil guns and optimize opacity until 2 pulverizers are in service.

MFT and IFT relays reset when the ignitor trip valve opens.

_____ 28. If units were not crosstied on auxiliary steam system, then open the auxiliary steam supply valve to allow the auxiliary steam line to warm up with the boiler and to prevent a drum level excursion if opened later. Close R.H. damper since there is no flow yet in the R.H. section.

_____ 29. Open the continuous blowdown 100% and use the boiler fill line from the condensate discharge header to maintain drum level in limits. If proper firing rate is held and blowdown controlled, -5" in drum is enough water, due to swelling, so as not to need to add water to boiler until 350 psi, so as to utilize #3 B.F.P.

_____ 30. Line up dampers and auxiliary equipment and start the primary air fans. Do not load fans at this time. Load when placing ball mills in service.

_____ 31. Verify three air compressors in service. Start the air heater blowing sequence using steam as the blowing medium, if the aux steam is crosstied. If not, use compressed air.

_____ 32. Firing rate must be controlled so as not to exceed 200·F between top and bottom drum metal temperature and 1000·F gas temperature on thermoprobes. Computer points for drum metal temps are: Unit 1 BT1007 through BT1016, AT^5 BC1003 through BC1007, Unit 2 BT2007 through BT2016, AT^5 BC2003 through BC2007.

NOTE: Thermoprobes unavailable, sacrificial probes installed in RH/SH areas will be utilized.

_____ 33. Jog down #7 F.W. heater outlet valve to approximately 5% open. If unable to jog down #7 F.W. heater, then jog down #8 F.W. heater outlet M.O.V. Jogging down is to assure S.H. sprays,

when necessary. Verify all other FW heaters inlet and outlet valves open.

_____ 34. Open the pegging steam valve to the D.A. It may be necessary to reduce valve position in order to obtain turbine seals later.

_____ 35. If crosstie aux. steam supply is not available pegging steam application is to be delayed until seals and vacuum are applied to the main turbine.

_____ 36. When 25 lbs. drum pressure is attained close the drum and superheater vents. Verify the "25 PSI drum pressure requirements" have been completed per the control room, unit and auxiliary operator boiler checklist (Attachments 1, 2 and 3). Verify flow through the main steam lead drains. If crossties aux. steam is unavailable reclose main steam lead drains until seals and vacuum are applied to the main turbine.

_____ 37. At approximately 150 PSI drum pressure the drum level will start to rise (swell). It may be necessary to utilize the mass blowdown to maintain drum level within limits. Firing rate can also be manipulated to control this. V-52's (2) can be utilized to assist in drum level control when mass blowdown becomes ineffective.

_____ 38. When 250 PSI drum pressure is attained, place the No. 3 boiler feed pump in service and close the condensate boiler fill valve. The mass blowdown should be opened to 50% at this time.

_____ 39. If boiler drum blowdown pH (1-XR-4042) is between 8.3 and 9.2, iron oxide is less than 200 ppb, and specific conductivity (1-CJR-40441) is between 2.5 and 3.5 mmho, continue increasing drum pressure as required. Lab personnel should provide hourly readings.

_____ 40. Condensate flow should already be sufficient to place the DA level control valve on automatic as well as hotwell make-up valves.

_____ 41. If boiler drum blowdown pH (1-XR-4042) is below 8.3, iron oxide is greater than 200 ppb, or specific conductivity (1-CJR-4041) is greater than 3.5 mmho due to ionic contamination, alternately open and close the boiler bottom drains for 30 seconds on each valve (not to exceed drum level limitations) between 400 PSI and 800 PSI drum pressure.

CAUTION: DO NOT BLOWDOWN USING BOILER BOTTOM DRAINS WHEN PRESSURE IS OVER 800 PSI.

42. Keep continuous boiler drum blowdown valve 100% open until water quality permits reduced blowdown rate. Mass blowdown is to be closed only when unit is stable on line, unless water quality/lab deems it necessary to do otherwise.

43. If vacuum was not pulled earlier, place the turbine gland steam function group in the "ON" position. This will open the drain on the gland steam header and start the warm-up period. Gland steam function group can be placed in stop-manual, and open drain manually also.

44. As soon as the temperature is adequate for the gland steam function group (superheat >90°F and aux. steam >446°F) the supply valve will open.

45. Ensure vacuum breakers are closed and have seal water on them, then start two vacuum pumps to establish vacuum.

46. When vacuum is established, reset the LP bypass system. Verify the LP stop valves open. (7" to 5" Hg) Check that LP bypass spray water is valved in. Should not reset without adequate spray water. Also reset the main turbine and verify the HP and IP stop valves open. Observe that the S/H spray control valves remain closed when the block valve resets.

47. Select idle mode on the turbomat and insure that the run up controller is in auto stop. Open HP warm-up valve.

48. At 400 psi start pressurizing and warming the electromatic power relief valves by slowly opening the bypass valves on both isolation valves. The relief valves must be warmed for at least 30 minutes prior to operating.

    At 500 psi have the Electromatics valved in. Then test them one at a time approximately 5 to 10 seconds. Be prepared for a sharp increase in drum level when this is done.

49. Uncross tie the units so that the unit being started up is supplying its own aux. steam prior to rolling the turbine.

50. With all FW heater inlet and outlet valves open (#7 FW heater or #8 outlet valve still jogged down) place all extractions in service.

51. A turbine driven boiler feed pump should be in service by the time drum pressure reaches 800 psi. If FW demand is not high enough to put the pump in the header then open the recirc. enough to maintain greater than 1200 rpm on the turbine, this should keep the exhaust temp within limits.

_____ 52. Load the PA fans at this time.

_____ 53. Prepare a lower mill for service by running through all S/U permissives to insure they can be met. All mills have water in mill drum. Drying out process should be completed at this time on mills number 5 and 6.

_____ 54. Parameters required during roll up of the turbine:
A. throttle pressure approx. 800 psi.
B. Main steam temperature 700·F.

_____ 55. Verify all turbine drains open oil temperature 85 to 110·F, > 40 psi header pressure, and stator cooling system in service, and generator H_2 pressure at 65 lbs. minimum.

_____ 56. Open the reheat pass damper to 10 - 25% open. **Caution:** this is to be done just prior to roll off. If roll off is delayed reclose the reheat pass damper.

_____ 57. With Tp at ~800 psi, main steam temp. at 700·F, prepare to roll the turbine off T/G.

CAUTION: Temperature may be difficult to control as little flow is present. Due to no HP by-pass i/s. Be careful so as to not over react.

_____ 58. Roll the turbine up to 500 RPM and hold for approximately 20 minutes. Check the turbine/generator for rubbing, vibration, oil flow, etc. (see 52 above)

_____ 59. If enough fire power is avail. with ignitors, roll the turbine up to 1200 RPM and hold for 20 minutes, while checking the turbine/generator for same conditions as above. (Check that T/G motor disengaged at 800 RPM.) (It may be necessary to put a loner mill i/s and fire very lightly, if ignitors are not adequate.)

NOTE: Turbine critical peaks at approximately 950 - 1000 rpm.

_____ 60. After reaching 1200 RPM and conditions stable, place a mill i/s and fire very lightly. If one is not already i/s stabilize conditions (drum and temp.). Once conditions are stable roll the turbine to 2200 rpm. Stabilize temperatures and pressures.

NOTE: Turbine critical peaks at approximately 1500 and 2100 rpm.

_____ 61. Roll the turbine up to 3600 RPM. The control system will roll the turbine up at a rate allowed by the HP and IP probes. 30/min. Check all turbine/generator supervisory

instrumentation as well as local checks.

NOTE: Turbine critical peaks at approximately 2800 rpm.

NOTE: Roll time will be approximately 2 hours from initial roll to rated speed. When 3600 RPM's is reached, notify dispatcher of intentions to synch. and tie.

_____ 62. By the time the turbine reaches 3600 ROMS a second mill should be put i/s with its Paso closed.

_____ 63. When the turbine reaches 3600 RPM select "LOAD" mode on turbomat, close the generator field breaker. Observe that generator terminal voltage increases, and is matched with grid voltage. When the turbine is synchronized, or sooner under certain conditions, notify FGD Control Room Operator.

_____ 64. Set the target load at 35 MWS and the load gradient at 25 MWS/MIN.

_____ 65. Remove one of the switches for the generator OCB's (either 8W50 or 8/W60) from the pull-to-lock position to the green flag position (normal after trip position).

_____ 66. Unlock the sync. switch for the corresponding breaker taken out of pull-to-lock in step #65. Turn the spring loaded sync. switch all the way to the "auto on" position and let it return to the "auto" position. The "auto" sync. circuit should automatically adjust the generator voltage to match the line voltage on the grid and the frequency. <u>THIS IS TO BE VERIFIED.</u> The selected OCB will not auto close in the "GREEN FLAG" position (normal after trip position). When frequency and voltage are matched, as the sync. scope is moving in the clockwise direction the selected OCB control switch is to be placed in the "RED FLAG" position <u>only</u> when the sync. scope is between the 10 o'clock and 12 o'clock position. If the OCB doesn't auto close between 10 o'clock and 12 o'clock it is to be placed back in the "GREEN FLAG" position until the sync. scope is moving clockwise and between 10 o'clock and 12 o'clock. Verify a breaker close signal is being sent by observing the synchronization red lamp illuminates in pulse fashion when the synchroscope pointer is between the 10 o'clock and 12 o'clock position. The OCB control switch should <u>never</u> be in the "RED FLAG" position unless these conditions exist or the OCB is close in. Upon synchronization, zero var's. (Do not totally depend on automatic mode!) If unable to sync. in auto take the sync. switch for the corresponding breaker taken out of pull-to-lock in step 65, and turn the sync. switch to manual. Use the frequency controller to adjust cycles so that the sync. scope

starts slowly turning in a clockwise direction. Re-verify that generator voltage and grid voltage are still matched. When the sync. scope indication is at 11 o'clock and approaching 12 o'clock, close the pre-selected OCB. Zero VAR's.

_____ 67. Verify unit load comes up to the target load set value that was set in step #64.

_____ 68. After stabilizing drum level, temperatures and pressure. Open the Paso on the 2nd mill, if not already done, and re-stabilize again.

_____ 69. Turn the selected sync. switch off. Unlock the other sync. switch and close the corresponding generator breaker.

_____ 70. Continue increasing load at no more than 5 MWS/MIN. using the turbotrol in load auto on and manually pecking the target load set value up. Remembering that more fuel from the mills and opening the turbine valves will still have impact on drum level and temps.

_____ 71. By this time one of TDBFPs could be put in automatic if not already.

_____ 72. Whenever stable coal fires are verified. Notify Supports so that TRs can be put i/s and modules as needed.

_____ 73. Whenever 10% steam flow is achieved. Complete the 10% flow checks. Transfer station service when load is > 200 mw.

_____ 74. When unit is stable at 250 MW, unit still in boiler manual/turbine base, TT42, @ 250 MW. Match throttle pressure control setpoint with actual pressure, and select turbine follow mode only. Boiler base should only be selected after feedwater temperature is constant. Reheat/econ. pass dampers should be placed in auto if not done already.

NOTE: When conditions indicate the HP warm up valve should be closed via the indications on the turbine control board direct an Operator to close valve.

_____ 75. Add mills as needed to continue increasing firing rate and load.

_____ 76. When unit is at 300 MWS it will be necessary to place the other boiler feed pump turbine in service. Once the second pump is in service the loading should be approximately equal and the second pump placed on automatic.

NOTE: The second pump should be brought into service slowly allowing the already in service pump to decrease automatically while maintaining drum level.

_____ 77. At 300 MWS all essential equipment should be in service to allow unit load capability throughout the entire load range. Equipment that is not required at this time should be in a "ready for service" type of condition. Also, throttle pressure can be increased to 2400 PSI if chemistry allows.

_____ 78. The generator hydrogen pressure should be at the 75 lb. maximum pressure.

_____ 79. Notify the dispatcher the unit is available for system load requirements within the 300 to 650 MW range.

NOTE: Any known restrictions that would prevent the unit from attaining full load (650 MWS) capability should be reported to the dispatcher at this time, or earlier, and logged on the derate information form.

1.0 PURPOSE

To provide an approved operating procedure for removing a unit from on-line status to off-line status for outage work.

2.0 SCOPE

This operating procedure will outline steps to be taken from full load operation to off-line/turning gear operation.

3.0 SKILL LEVEL

When performing this task, it will require no less than the proficiency of a Control Room Operator, Unit Operator and Auxiliary Operator.

4.0 RESPONSIBILITIES

It shall be the responsibility of the Control Room Operator to perform the following:

4.1 Ensure the Unit is maintained in a stable condition throughout all load drops to off-line status.

4.2 Ensure all equipment is removed from service and secured properly in a timely manner.

4.3 Ensure that all required permissive and logics are met as required when reducing load and removing Unit from the grid.

4.4 Ensure that the shutdown procedure is followed throughout its entirety. Should any deviation be required, authorization from the Shift Supervisor must be obtained first. Exception to this rule is (1) safety to personnel or equipment or (2) if stipulated in this procedure, authorizing deviation without prior approval.

4.5 Maintain an open communication with all departments involved at ALL times.

5.0 REMOVING THE UNIT FROM SERVICE

NOTE 1: **Assume Unit is at 650 MWs, 5 and 2/3 mills in service, 2400 psi throttle pressure, 1000 degrees main steam temperature, 4 ID fans in service and associated modules for full load requirements.**

NOTE 2: **Upon notice of Unit being removed from service, clean the boiler of slag with the sootblowing system. It will require approximately 5 hours to complete the cleaning process using all blowers.**

5.1 Select DEB/LFC or DEB/TB mode at a 5 MW a minute ramp rate. Deviation to ramp rate is authorized to accommodate state load requirements. Deviation from Boiler/Turbine modes is also authorized if they are not available or stable.

5.2 Begin decreasing MW's (load) at the given ramp rate. As load is reduced, slide pressure to maintain turbine valve position at no less than 90% valve position. Large load drops may result in a valve position less than 90%. Continue sliding pressure after load drop until 90% or greater turbine valve position is achieved. This valve position is to maintain steam flow velocities to assist in cooling the turbine/boiler. This accelerated flow rate will aid in control of steam temperatures at lower loads.

5.3 Reduce the Main steam and Hot Reheat steam temperature set points to a degree not to exceed the minimum BBC requirements. BBC requires no less than 150 degrees of steam temperature above saturation point being admitted to the turbines. (Reference Steam Tables)

5.4 Reducing thermal MWs for load reduction is done by removing fire power, i.e., mills from service. Dependent upon related outage repair requirements when removing a mill from service, stripping and/or emptying the silo may be required. If there is not any related outage work to be performed, the CRO will remove the mill from service by the normal accepted practice.

5.5 Repairs requiring the silo to be emptied will require at least twelve hours advanced notice. This will give adequate time for pre-planning to ensure that the silo is prepared properly allowing repairs to be performed during unit shut down.

NOTE: When and at what load to remove fire power is at the discretion of the Control Room Operator. Unit fire power configuration is dictated by the mills and burners available for use. Another determining factor is the need introduced by pre-planning as to which mill is removed from service first and in what desired order.

6.0 LOAD REDUCTION

6.1 Reduce load by reducing fire power from the upper mills first. Remove the upper mills, if able: first, Mill #1 and then Mill #3.

6.2 When dropping load, constant monitoring of the HP/IP probes is required. There is an expected deflection to occur to the probes. The probes are expected to respond by indicating 50% towards the negative direction on the probe chart. This is acceptable. However, sharp increases in position (spikes) or an elevated percentage above 65% will require the immediate attention of the Control Room Operator.

6.3 Monitor throttle pressure and drum pressures frequently. These pressures must remain stable. Unstable throttle or drum pressures will not be conducive of a controlled shutdown.

6.4 Monitor main steam temperature vigilantly throughout all load reductions and constant conditions. Main steam temperature becomes increasingly

difficult to maintain at a steady rate as low load and low flow conditions become realized.

6.5 UNIT STATUS:

6.5.1 LOAD AT 580 MWS.

6.5.2 THROTTLE PRESSURE 2300 PSI APPROXIMATELY.

6.5.3 FIVE MILLS IN SERVICE.

6.5.4 MAIN STEAM TEMPERATURE 950 DEGREES AND APPROXIMATELY 300 DEGREES SUPERHEAT.

6.5.5 FOUR ID FANS IN SERVICE.

6.5.6 FOUR MODULES IN SERVICE.

6.6 Remove one of the four ID Fans from service as soon as load conditions permit. This will allow Supports to remove one module from service as long as logics are met.

6.7 Have the Unit Operator verify that the hood sprays are lined up for service.

6.8 Place the Start Up Boiler Feed Pump in service. Do not initiate any increases to the pump output at this time, i.e., feed pump discharge being placed into the feedwater header. Placing the Start Up Boiler Feed Pump in service is only to ensure pump operation. Placing the pump in service at this time will supply ample time for check out and field repairs if any are needed.

6.9 UNIT STATUS:

6.9.1 450 MWS.

6.9.2 FOUR MILLS IN SERVICE.

6.9.3 THROTTLE PRESSURE AT 1800 PSI.

6.9.4 MAIN STEAM TEMPERATURE 900 DEGREES, SUPERHEAT STEAM 270 DEGREES.

6.9.5 THREE ID FANS IN SERVICE.

6.9.6 THREE MODULES IN SERVICE.

NOTE: To obtain 900 degrees main steam temperature, it will require the #7 FWH discharge valve to be throttled to 25%. This will produce sufficient spray flow to the sprays to control superheat temperature at the desired temperature. CAUTION: When 35% open on the #7 FWH discharge valve has

been obtained, reduce as needed, not to exceed the 25% mark. Closely monitor drum level chart. Should drum level become erratic at anytime, open the discharge valve to 50% and wait until load begins to drop below 450 MWs. Should temperature of 900 degrees still be a problem to obtain, blow the wall blowers as well as bull nose sootblowers. The economizer damper should already be 100% open at this time. If it is not, open the economizer to 100% now.

NOTE: If the Unit is being shut down for short term repairs to something other than boiler internals or turbine/generator, there is no need to reduce temperatures to the degree outlined in this procedure.

NOTE: To control main steam temperature at the required parameters, additional spray pressure may be required. To attain this, begin throttling the outlet of the #7 feedwater heater. Do not, however, throttle the #7 feedwater heater outlet valve below 5% at anytime.

NOTE: Prior to closing module dampers, remove all but two absorber recycle pumps from service. If unit is coming off line for a scheduled outage and fast cool down is required, three modules must be left in service with the bypass isolation damper open 100%. Modules left in service for fast cool down require three absorber recycle pumps left in service and one wash pump left in service. After completion of fast cool down, remaining three modules will be removed from service once only two ID Fans or less are in service.

6.10 Check to ensure the auxiliary steam system is valved in and operational from the boiler source.

6.11 <u>UNIT STATUS:</u>

6.11.1 300 MWS.

6.11.2 THREE MILLS IN SERVICE.

6.11.3 THROTTLE PRESSURE 1400 PSI.

6.11.4 MAIN STEAM TEMPERATURE 800 DEGREES, SUPERHEAT APPROXIMATELY 212 DEGREES.

6.11.5 THREE ID FANS IN SERVICE.

6.12 Test the HP bypass operation electronically and actually. Perform the electronic test procedure through the test mode located at the HP bypass panel. Actual test will be opening the HP bypass slightly to ensure all components work properly.

6.13 Remove one of the Steam Driven Boiler Feed Pumps from service under 300 MWS.

6.14 If unit is coming off line and fast cool down is not required, modules will be removed from service as follows:

6.14.1 Unit status reaches 450 MWs or less and only three ID Fans in service or less, remove fourth module from service.

6.14.2 Unit status reaches 300 MWs or less with two ID Fans still in service, remove the third module from service.

6.14.3 Place precipitator seal air fans in manual.

7.0 TURBINE SOAKING

Should repairs necessitate reduction of metal temperatures, soak time must be at least two to three hours consecutively in duration to remove the latent heat. Steam flow of approximately 2.5 million lbs. per hour should equate out to ~275 to 300 MWS. Ensure that the throttle pressure versus main steam temperatures are such that 150 degrees superheat steam temperature above saturation is maintained at all times. (REFERENCE STEAM TABLES)

NOTE: Unit loads below 300 MWS place the Unit Master Control in a boiler base mode to ensure stable unit operation.

NOTE: Swap station service at approximately 200 MWs.

8.0 LOAD REDUCTION CONTINUED

8.1 Remove the fourth mill at approximately 190 MWS. This MW value is flexible and fire power requirements should dictate at what time the mill is removed from service. However, when this mill is removed from service, the fifth mill should be prepared for removal.

8.2 UNIT STATUS:

8.2.1 150 MWS.

8.2.2 TWO MILLS IN SERVICE.

8.2.3 THROTTLE PRESSURE 1000 PSI.

8.2.4 MAIN STEAM TEMPERATURE ~750 DEGREES AND APPROXIMATELY 205 DEGREES SUPERHEAT.

8.2.5 THREE ID FANS IN SERVICE.

8.3 When the Unit is stable and at 150 MWS, request authorization from the dispatcher to remove the Unit from operation. When authorization is obtained, prepare the Unit for final load reduction. Place HP bypass in service at 1000 psi set point. With the HP bypass in service, boiler energy from the boiler will be diverted through the HP bypass. This will

reduce the impact to the boiler pressure and alleviate drum level excursions.

9.0 REMOVING UNIT FROM THE GRID

9.1 Reduce load by reducing valve position in the turbine manual mode. Be advised that when C valve closes, the probes will indicate a sharp change in position. C valve should be fully closed by 85% indication of the live steam valve position indication located on TT42. Actual valve position can be seen on the Bently Nevada panel.

9.2 When C valve indicates closed, Unit load should be such that one of the two remaining mills may be removed from service. Prepare the last mill for removal, i.e., cool the mill down.

9.3 Once load has been reduced to 50 MWs, place the turbine controls in the idle mode load gradient above 3 MWs a minute and the Unit will decrease rapidly to zero MWs. HP bypass will be opened a significant amount by this time, however, the amount that it is open can be dictated by the amount of thermal MWs left in the boiler. Decrease thermal MWs with the reduction of fire power so as not to exceed 80% of HP bypass valve position.

9.4 <u>UNIT STATUS:</u>

9.4.1 TURBINE/GENERATOR OFF LINE.

9.4.2 THROTTLE PRESSURE 1000 PSI.

9.4.3 ONE MILL IN SERVICE.

9.4.4 ONE TURBINE DRIVEN BOILER FEED PUMP IN SERVICE.

9.4.5 THREE ID FANS IN SERVICE.

9.5 With no Tests/PMs required, remove the last mill from service, purging all coal conduits. Once the last coal fire is out and coal conduits are purged, remove and purge out all ignitors.

9.6 When boiler comes off line and MFT relay activates, T/R sets trip automatically.

9.6.1 Open scrubber bypass isolation damper 100%.

9.6.2 Remove the remaining two modules from service. As absorber recycle pumps are taken out of service, flush all pumps and isolate seal water.

9.6.3 As absorber modules are removed from service, isolate supernate root valves, reagent addition control valves and service water supply

to the mist eliminator sprays.

9.6.4 Place T/R set control switches in the OFF position.

9.6.5 Remove reagent transfer pump from service. After completion of automatic pump flush, valve in manual loop header flush until clear water is observed in return loop to reagent storage thank, then isolate manual loop flush supply.

9.7 Check to ensure main turbine turning gear comes into operation at 600 RPMs and that it maintains 25 RPMs on the rotor.

9.8 Isolate both electromatic power relief valves at 500 psi by closing the isolation gate valves and the isolation valve bypass valves.

9.89 Continue to depressurize the boiler through the HP/LP bypass loop down to the desired pressure ~200 to 300 psi.

9.910 When boiler depressurization is complete, fully break condenser vacuum. Vacuum may require being broken earlier if turbine steam seals are lost.

NOTE: If the Main Turbine did not reach turning gear RPMs at "9.7" of this procedure, RPM deceleration will increase now that vacuum is broken. Monitor Turbine speed to ensure proper operation of the turning gear occurs.

APPENDIX B

EMISSION INVENTORY WORKSHEETS

EMISSION INVENTORY WORKSHEET

Seminole Electric Cooperative – Seminole Power Plant

U–001

PROJECT INFORMATION

COAL COMBUSTION – CRITERIA POLLUTANTS | Process Doc. II.D.3.3.

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Unit No. 1; Coal Fired
Emission Control Method(s)/ID No.(s):	Electrostatic Preciptator (ESP), Wet Limestone Flue Gas Desulfurization (FGD)
Emission Point ID:	U–001

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Heat Input (MMBtu/hr) x Pollutant Emission Rate (lb/MMBtu)

Emission (ton/yr) = Heat Input (MMBtu/hr) x Pollutant Emission Rate (lb/MMBtu) x Operating Period (hrs/yr) x (1 ton/2,000 lb)

Source: ECT, 1996.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours: 24 Hrs/Day 7 Days/Wk 8,760 Hrs/Yr

Criteria Pollutant	Heat Input (MMBtu/hr)	Controlled Pollutant Emission Rate (lb/MMBtu)	Potential Emission Rates (lb/hr)	Potential Emission Rates (tpy)
SO_2	7,172	0.994	7130.0	31229.4
NO_x	7,172	0.6	4303.2	18848.0
PM	7,172	0.03	215.2	942.4

SOURCES OF INPUT DATA

Variable	Data Source
Operating Hours	SECI, 1996.
Heat Input	30–day average; SECI, 1996.
Controlled Emission Rates; SO_2, NO_x, PM	PSD–FL–018 and 40 CFR Part 60, Subpart Da.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T. Davis	Date:	7/12/94
Evaluated by:	T. Davis	Date:	5/9/96
Data Entered by:	A. Trbovich	Date:	10/30/94
Reviewed by:		Date:	

EMISSION INVENTORY WORKSHEET

Seminole Electric Cooperative – Seminole Power Plant

U–002

PROJECT INFORMATION

COAL COMBUSTION – CRITERIA POLLUTANTS | Process Doc. II.D.3.3.

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Unit No. 2; Coal Fired
Emission Control Method(s)/ID No.(s):	Electrostatic Preciptator (ESP), Wet Limestone Flue Gas Desulfurization (FGD)
Emission Point ID:	U–002

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Heat Input (MMBtu/hr) x Pollutant Emission Rate (lb/MMBtu)

Emission (ton/yr) = Heat Input (MMBtu/hr) x Pollutant Emission Rate (lb/MMBtu) x Operating Period (hrs/yr) x (1 ton/2,000 lb)

Source: ECT, 1994.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours: 24 Hrs/Day 7 Days/Wk 8,760 Hrs/Yr

Criteria Pollutant	Heat Input (MMBtu/hr)	Controlled Pollutant Emission Rate (lb/MMBtu)	Potential Emission Rates (lb/hr)	Potential Emission Rates (tpy)
SO_2	7,172	0.994	7130.0	31229.4
NO_x	7,172	0.6	4303.2	18848.0
PM	7,172	0.03	215.2	942.4

SOURCES OF INPUT DATA

Variable	Data Source
Operating Hours	SECI, 1994.
Heat Input	30–day average; SECI, 1996.
Controlled Emission Rates; SO_2, NO_x, PM	PSD–FL–018 and 40 CFR Part 60, Subpart Da.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T. Davis	Date:	7/12/94
Evaluated by:	T. Davis	Date:	5/9/96
Data Entered by:	A. Trbovich	Date:	10/30/94
Reviewed by:		Date:	

EMISSION INVENTORY WORKSHEET

Seminole Electric Cooperative – Seminole Power Plant

L–001

PROJECT INFORMATION

MATERIAL TRANSFER – CONTROLLED EMISSION SOURCES | Process Doc. II.D.2.4.

FACILITY AND SOURCE DESCRIPTION

Emission Source Description: Limestone Handling System: Truck Unloading and Limestone Breaking

Emission Control Method(s)/ID No.(s): Panel Filter/ DC–1

Emission Point ID: L–001 | **Transfer Point ID(s):** L–T1, L–T2, L–T3

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Flow Rate (scfm) x (grain/scf) x (1 lb/7,000 grain) x (60 min/hr)

Emission (tpy) = Flow Rate (scfm) * (grain/scf) * (1 lb/7,000 grain) x (60 min/hr) x hrs/yr x (1 ton/2,000 lb)

Source: ECT, 1996.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours: 24 Hrs/Day 7 Days/Wk 8,760 Hrs/Yr

Transfer Points Controlled By Common Control Device	Transfer Point ID No.	Exhaust Flow Rate (scfm)	Exit Grain Loading (gr/scf)	Potential PM_{10} Emission Rates (lb/hr)	(tpy)
Truck Unloading to Below Grade Hopper	L–T1	3,325	0.02	0.57	2.49
Below Grade Hopper to Feeder/Breaker CB–1	L–T2				
Feeder Breaker CB–1 to Conveyor CB2	L–T3				

SOURCES OF INPUT DATA

Variable	Data Source
Operating Hours	SECI, 1994.
Exhaust Flow Rate	SECI, 1994. Vendor data.
Exit Grain Loading	ECT, 1996. Typical exit loading.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T. Davis	Date:	7/12/94
Evaluated by:	T. Davis	Date:	5/14/96
Data Entered by:	A. Trbovich	Date:	11/4/94
Reviewed by:		Date:	

EMISSION INVENTORY WORKSHEET

Seminole Electric Cooperative – Seminole Power Plant

FGD–001

PROJECT INFORMATION

MATERIAL TRANSFER – CONTROLLED EMISSION SOURCES

Process Doc. II.D.2.5.

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	FGD Sludge Stabilization System: South Lime Railcar Pneumatic Unloading		
Emission Control Method(s)/ID No.(s):	Baghouse/ VR–152		
Emission Point ID:	FGD–001	Transfer Point ID(s):	FGD–T1

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Flow Rate (scfm) x (grain/scf) x (1 lb/7,000 grain) x (60 min/hr)

Emission (tpy) = Flow Rate (scfm) x (grain/scf) x (1 lb/7,000 grain) x (60 min/hr) x hrs/yr x (1 ton/2,000 lb)

Source: ECT, 1994.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours: 24 Hrs/Day 7 Days/Wk 8,760 Hrs/Yr

Transfer Points Controlled By Common Control Device	Transfer Point ID No.	Exhaust Flow Rate (scfm)	Exit Grain Loading (gr/scf)	Potential PM_{10} Emission Rates (lb/hr)	(tpy)
South Lime Railcar Pneumatic Unloading	FGD–T1	1,994	0.02	0.34	1.50

SOURCES OF INPUT DATA

Variable	Data Source
Operating Hours	SECI, 1994.
Exhaust Flow Rate	SECI, 1994. Vendor data.
Exit Grain Loading	ECT, 1994. Typical exit loading.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T. Davis	Date:	7/12/94
Evaluated by:	A. Trbovich	Date:	11/4/94
Data Entered by:	A. Trbovich	Date:	11/4/94
Reviewed by:		Date:	

EMISSION INVENTORY WORKSHEET

Seminole Electric Cooperative – Seminole Power Plant

FGD–002

PROJECT INFORMATION

MATERIAL TRANSFER – CONTROLLED EMISSION SOURCES

Process Doc. II.D.2.5.

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	FGD Sludge Stabilization System: North Lime Railcar Pneumatic Unloading		
Emission Control Method(s)/ID No.(s):	Baghouse/ VR–151		
Emission Point ID:	FGD–002	Transfer Point ID(s):	FGD–T2

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Flow Rate (scfm) x (grain/scf) x (1 lb/7,000 grain) x (60 min/hr)

Emission (tpy) = Flow Rate (scfm) x (grain/scf) x (1 lb/7,000 grain) x (60 min/hr) x hrs/yr x (1 ton/2,000 lb)

Source: ECT, 1994.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours: 24 Hrs/Day 7 Days/Wk 8,760 Hrs/Yr

Transfer Points Controlled By Common Control Device	Transfer Point ID No.	Exhaust Flow Rate (scfm)	Exit Grain Loading (gr/scf)	Potential PM_{10} Emission Rates (lb/hr)	(tpy)
North Lime Railcar Pneumatic Unloading	FGD–T2	1,994	0.02	0.34	1.50

SOURCES OF INPUT DATA

Variable	Data Source
Operating Hours	SECI, 1994.
Exhaust Flow Rate	SECI, 1994. Vendor data.
Exit Grain Loading	ECT, 1994. Typical exit loading.

NOTES AND OBSERVATIONS

No visible emissions observed during operation.

DATA CONTROL

Data Collected by:	T. Davis	Date:	7/12/94
Evaluated by:	A. Trbovich	Date:	11/4/94
Data Entered by:	A. Trbovich	Date:	11/4/94
Reviewed by:		Date:	

EMISSION INVENTORY WORKSHEET

Seminole Electric Cooperative – Seminole Power Plant

FGD–003

PROJECT INFORMATION

MATERIAL TRANSFER – CONTROLLED EMISSION SOURCES

Process Doc. II.D.2.5.

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	FGD Sludge Stabilization System: Lime Pneumatic Transfer to Silo V–152		
Emission Control Method(s)/ID No.(s):	Baghouse/ DC–152		
Emission Point ID:	FGD–003	Transfer Point ID(s):	FGD–T3, FGD–T4

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Flow Rate (scfm) x (grain/scf) x (1 lb/7,000 grain) x (60 min/hr)

Emission (tpy) = Flow Rate (scfm) x (grain/scf) x (1 lb/7,000 grain) x (60 min/hr) x hrs/yr x (1 ton/2,000 lb)

Source: ECT, 1994.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours: 24 Hrs/Day 7 Days/Wk 8,760 Hrs/Yr

Transfer Points Controlled By Common Control Device	Transfer Point ID No.	Exhaust Flow Rate (scfm)	Exit Grain Loading (gr/scf)	Potential PM_{10} Emission Rates (lb/hr)	(tpy)
Quicklime Railcar Unloading To North Quicklime Silo V–152	FGD–T3	2,600	0.02	0.45	1.95
Quicklime Truck Unloading To North Quicklime Silo V–152	FGD–T4				

SOURCES OF INPUT DATA

Variable	Data Source
Operating Hours	SECI, 1994.
Exhaust Flow Rate	SECI, 1994. Vendor data.
Exit Grain Loading	ECT, 1994. Typical exit loading.

NOTES AND OBSERVATIONS

No visible emissions observed during operation.

DATA CONTROL

Data Collected by:	T. Davis	Date:	7/12/94
Evaluated by:	A. Trbovich	Date:	11/4/94
Data Entered by:	A. Trbovich	Date:	11/4/94
Reviewed by:		Date:	

EMISSION INVENTORY WORKSHEET

Seminole Electric Cooperative – Seminole Power Plant

FGD–004

PROJECT INFORMATION

MATERIAL TRANSFER – CONTROLLED EMISSION SOURCES

Process Doc. II.D.2.5.

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	FGD Sludge Stabilization System; Lime Pneumatic Transfer to Silo V–151		
Emission Control Method(s)/ID No.(s):	Baghouse/ DC–151		
Emission Point ID:	FGD–004	Transfer Point ID(s):	FGD–T5, FGD–T6

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Flow Rate (scfm) x (grain/scf) x (1 lb/7,000 grain) x (60 min/hr)

Emission (tpy) = Flow Rate (scfm) x (grain/scf) x (1 lb/7,000 grain) x (60 min/hr) x hrs/yr x (1 ton/2,000 lb)

Source: ECT, 1994.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours: 24 Hrs/Day 7 Days/Wk 8,760 Hrs/Yr

Transfer Points Controlled By Common Control Device	Transfer Point ID No.	Exhaust Flow Rate (scfm)	Exit Grain Loading (gr/scf)	Potential PM_{10} Emission Rates (lb/hr)	(tpy)
Quicklime Railcar Unloading To South Quicklime Silo V–151	FGD–T5	2,600	0.02	0.45	1.95
Quicklime Truck Unloading To South Quicklime Silo V–151	FGD–T6				

SOURCES OF INPUT DATA

Variable	Data Source
Operating Hours	SECI, 1994.
Exhaust Flow Rate	SECI, 1994. Vendor data.
Exit Grain Loading	ECT, 1994. Typical exit loading.

NOTES AND OBSERVATIONS

No visible emissions observed during operation.

DATA CONTROL

Data Collected by:	T. Davis	Date:	7/12/94
Evaluated by:	A. Trbovich	Date:	11/4/94
Data Entered by:	A. Trbovich	Date:	11/4/94
Reviewed by:		Date:	

APPENDIX C

CURRENT PERMITS

Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

September 8, 1995

Mr. Jim Alves
Hopping Green Sams & Smith
Post Office Box 6526
Tallahassee, Florida 32314

Dear Mr. Alves:

The Seminole Conditions of Certification has been recompiled to agree with the final order of March 2, 1995. The Siting Coordination Office has provided your office with a copy of the revised conditions for your files.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Office

Conditions of Certification

State of Florida Department of Environmental Protection
Seminole Electric Cooperative, Inc.
Seminole Units 1 & 2
PA 78-10
CONDITIONS OF CERTIFICATION

Table of Contents

State of Florida Department of Environmental Protection
Seminole Electric Cooperative, Inc.
Seminole Units 1 & 2
PA 78-10

CONDITIONS OF CERTIFICATION

I. Air

The construction and operation of Units No. 1 and 2 at the Seminole steam electric power plant site shall be in accordance with all applicable provisions of Chapters 62-210, 62-212, 62-213, 62-296, and 62-297, Florida Administrative Code. In addition to the foregoing, the permittee shall comply with the following conditions of certification:

A. Emission Limitations

1. Stack emissions from Units 1 and 2 shall not exceed the following when burning bituminous coal:

1.a. SO_2 - 1.20 lb. per million Btu heat input, and 10 percent of the potential combustion concentration (90 percent reduction).

1.b. NO_x - 0.60 lb. per million Btu heat input, and 35 percent of the potential combustion concentration (65 percent reduction).

1.c. Particulates - 0.03 lb per million Btu heat input and 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel.

1.d. Compliance with the emission limitations and percent reductions in 1.a. and 1.b. shall be determined on a 30-day rolling average.

1.e. Compliance with the particulate matter emission limitation under 40 C.F.R. §60.42a(a)(1) (paragraph 1.c., above) constitutes compliance with the percent reduction requirements for particulate matter and compliance with the nitrogen oxides emission limitation under 40 C.F.R. §60.44a(a) (paragraph 1.b., above) constitutes compliance with the percent reduction requirements for nitrogen oxides.

2. The height of the boiler exhaust stack for Units No. 1 & 2 shall not be less than 675 ft. above grade.

3. Particulate emissions from the coal handling facilities:

   a. The applicant shall not cause to be discharged into the atmosphere from any coal processing or conveying equipment, coal storage system or coal transfer and loading system processing coal, visible emissions which exceed 20 percent opacity. Particulate emissions shall be controlled by use of control devices having a removal efficiency of not less than 99.9%.

   b. The applicant must submit to the Department within ten working days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal handling facility. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of such devise if the Department determines the selected control device to be inadequate to meet the emission limits specified in 3. a. above. Such disapproval shall be issued within 30 days of receipt of the technical data.

4. Particulate emissions from the FGD sludge fixing facility shall be in compliance with Section 62-296.310(2).

B. <u>Air Monitoring Program</u>

1. The permittee shall install and operate continuous monitoring devices for the Units No. 1 & 2 boiler exhausts for sulfur dioxide, nitrogen dioxide and opacity. The monitoring devices shall meet the applicable requirements of Rule 62-296.800, F.A.C., and 40 C.F.R. 60. The opacity monitor may be placed in the duct work between the electrostatic precipitator and the FGD scrubber.

2. The permittee shall operate an ambient monitoring device for sulfur dioxide in accordance with EPA reference methods in 40 C.F.R. Part 53 and an ambient monitoring device for suspended particulates as shown on Figure 1. The monitoring device shall be specifically located at a location approved by the Department. The frequency of operation shall be every six days commencing as specified by the Department.

3. The permittee shall maintain a daily log of the amounts and types of fuels used and copies of fuel analyses containing information on sulfur content, ash content and heating values.

4. The permittee shall provide sampling ports into the stack and shall provide access to the sampling ports in accordance with Rule 62-297.345, F.A.C., and 40 C.F.R. 60.8.

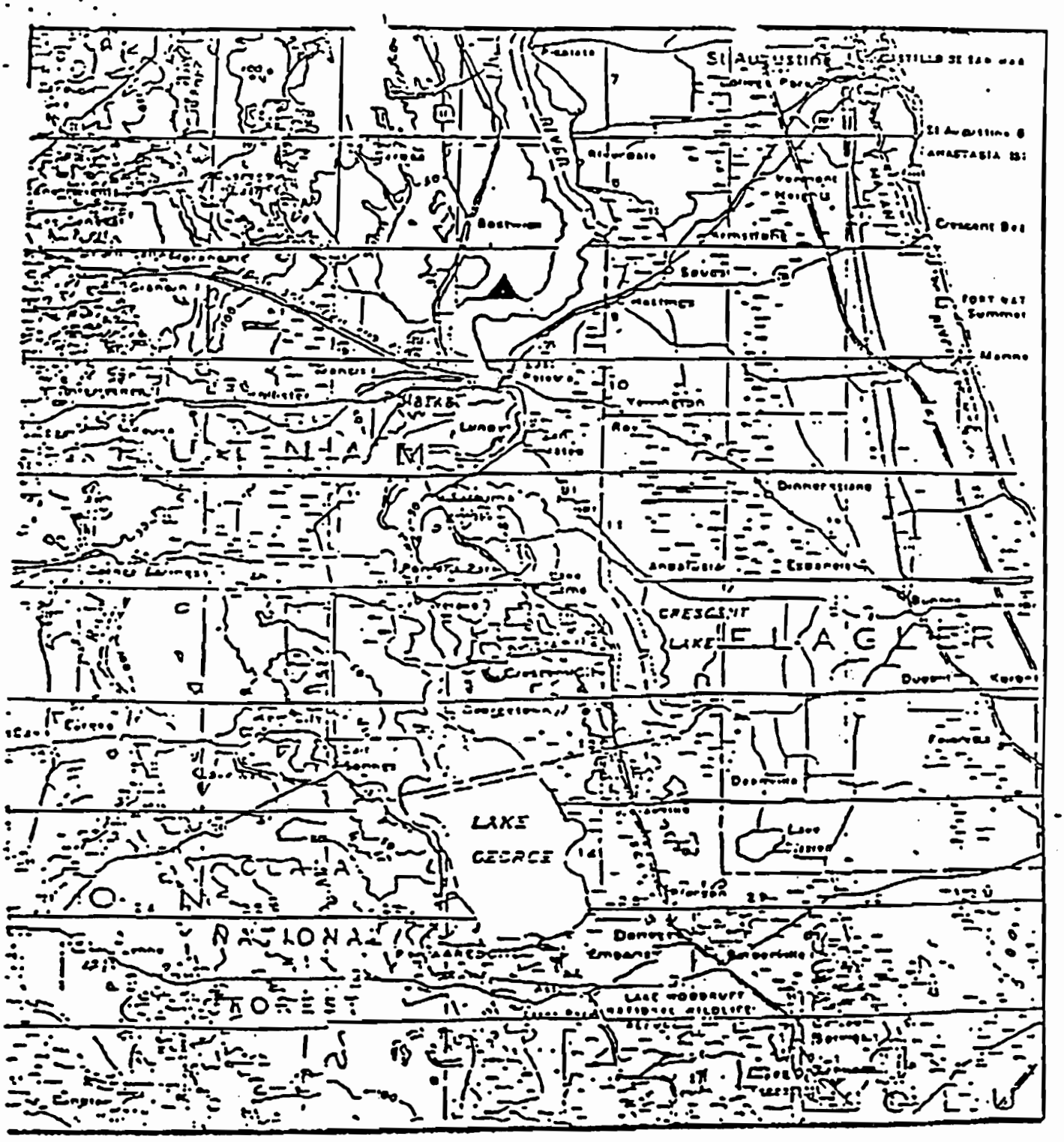
5. The ambient monitoring program may be reviewed annually beginning two years after start-up of Unit No. 2 by the Department and the permittee.

6. Prior to operation of the source, the applicant shall submit to the Department a standardized plan or procedure that will allow the applicant to monitor emission control equipment efficiency and enable the applicant to return malfunctioning equipment to proper operation as expeditiously as possible.

C. Stack Testing

1. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the owner or operator shall conduct performance tests for particulates and SO_2 and furnish the Department a written report of the results of such performance tests.

2. Compliance tests for particulate matter shall be conducted and data reduced in accordance with Rule 62-297.330, Table 62-297.330-1, F.A.C.



▲ FIGURE 1: Location of Ambient Air Quality Monitoring Station

3. Compliance tests shall be conducted under such conditions as the Department shall specify based on representative compliance of the facility. The owner or operator shall make available to the Department such records as may be necessary for the Department to determine the appropriate operating conditions of the compliance tests.

4. The owner or operator shall provide 15 days prior written notice of the compliance tests to afford the Department the opportunity to have an observer present.

5. Compliance tests for particulates shall be performed annually during a testing period that commences not earlier than 60 days before and not later than 60 days after the anniversary date of the last compliance test in accordance with Conditions C.2, 3, and 4 above, provided that the requirements of Rule 62-297.340(1)(d), F.A.C., for testing each fiscal year (October-September 30) are met. If the plant is shut down for reasons beyond the control of the owner such that testing during the normal testing period cannot be accomplished, the annual compliance test shall be performed within 60 days after the unit is restarted and reaches its normal commercial production rate.

6. SO_2 and NO_x Continuous Emission Monitors required by Rule 62-297.500, F.A.C., and 40 C.F.R. 60 subpart Da shall comply with the quality assurance requirements for continuous emission monitoring systems described in 40 C.F.R. 60, Appendix F.

D. Reporting

1. For each Unit, stack monitoring, fuel usage and fuel analysis data shall be reported to the Department on a quarterly basis in accordance with Rule 62-296.800, F.A.C.

2. Ambient air monitoring data shall be reported to the Department quarterly commencing on the date of certification by the last day of the month following the quarterly reporting period utilizing the SAROAD or other format approved by the Department in writing.

3. Beginning one month after certification the applicant shall submit to the Department a quarterly status report briefly outlining progress made on engineering design and purchase of major pieces of equipment (including control equipment). All reports and information required to be submitted under this condition shall be submitted to the Administrator of Power Plant Siting, Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32301.

II. Water Discharges

Any discharges into waters of the State during construction and operation of Units No. 1 & 2 shall be in accordance with all applicable provisions of Chapters 62-302 and 62-520, Florida Administrative Code and 40 C.F.R. 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category except as provided herein. Also the permittee shall comply with the following conditions of certification.

A. Plant Effluents and Receiving Body of Water

For discharges made from the power plant the following conditions shall apply.

1. Receiving Body of Water (RBW)

The receiving body of water has been determined by the Department to be those waters of the St. Johns River and any other water affected which are considered to be waters of the State within the definition of Chapter 403, Florida Statutes.

2. Point of Discharge (POD)

The point of discharge will be determined by the Department to be where the effluent physically enters the waters of the State.

3. Thermal Mixing Zone

The instantaneous zone of thermal mixing for cooling tower blowdown shall not exceed an area of 1705 square feet at a daily average discharge temperature of 95° F. During discharge, the blowdown from the cooling towers for Units 1 & 2 shall be withdrawn at

the point of lowest temperature of the recirculating cooling water prior to the addition of makeup water. The temperature at the point of discharge into the St. Johns River shall not be greater than 98 degrees F, nor shall it exceed 95° F on a daily average. The temperature of the water at the edge of the mixing zone shall not exceed the limitations of Paragraph 62-302.520(4)(a), F.A.C., except on occasions in which the temperature of the unaffected receiving waters exceeds 92 degrees F.

4. Chemical Wastes and Boiler Blowdown

All discharges of low volume wastes (demineralizer regeneration, floor drainage, lab drains and similar wastes), shall comply with Chapter 62-302. If violations of Chapter 62-302 occur, corrective action shall be taken. These wastewaters shall be discharged to an adequately sized and constructed treatment facility. Operational cleaning wastes shall be treated to comply with 40 CFR Part 423 and Chapter 62-302, F.A.C., prior to discharge. Boiler blowdown, boiler fireside wash, air preheater wash, and stack wash shall be disposed of in an adequately sized percolation pond; provided, however, that boiler blowdown from either unit may also be recycled to the Unit 1 and 2 cooling towers.

5. Coal Pile and Limestone Pile

Coal pile runoff and Limestone Pile runoff from less than 10-year 24-hour rainfall shall be treated as required to limit the suspended solids to 50 mg/l and to prevent increases in turbidity to less than 50 JTU in waters of the State beyond a distance of 150 meters from the POD.

6. Cooling Tower Blowdown

The cooling tower blowdown shall contain no detectable amounts of material added for corrosion inhibition, including but not limited to zinc and chromium.

7. Chlorine

The quantity of total residual chlorine discharged in the blowdown from the cooling tower shall not exceed 0.1 mg/l at the POD nor 0.01 mg/l beyond an instantaneous mixing zone of 750 square feet. There will be no limit on the duration of discharge of chlorine.

8. Ph

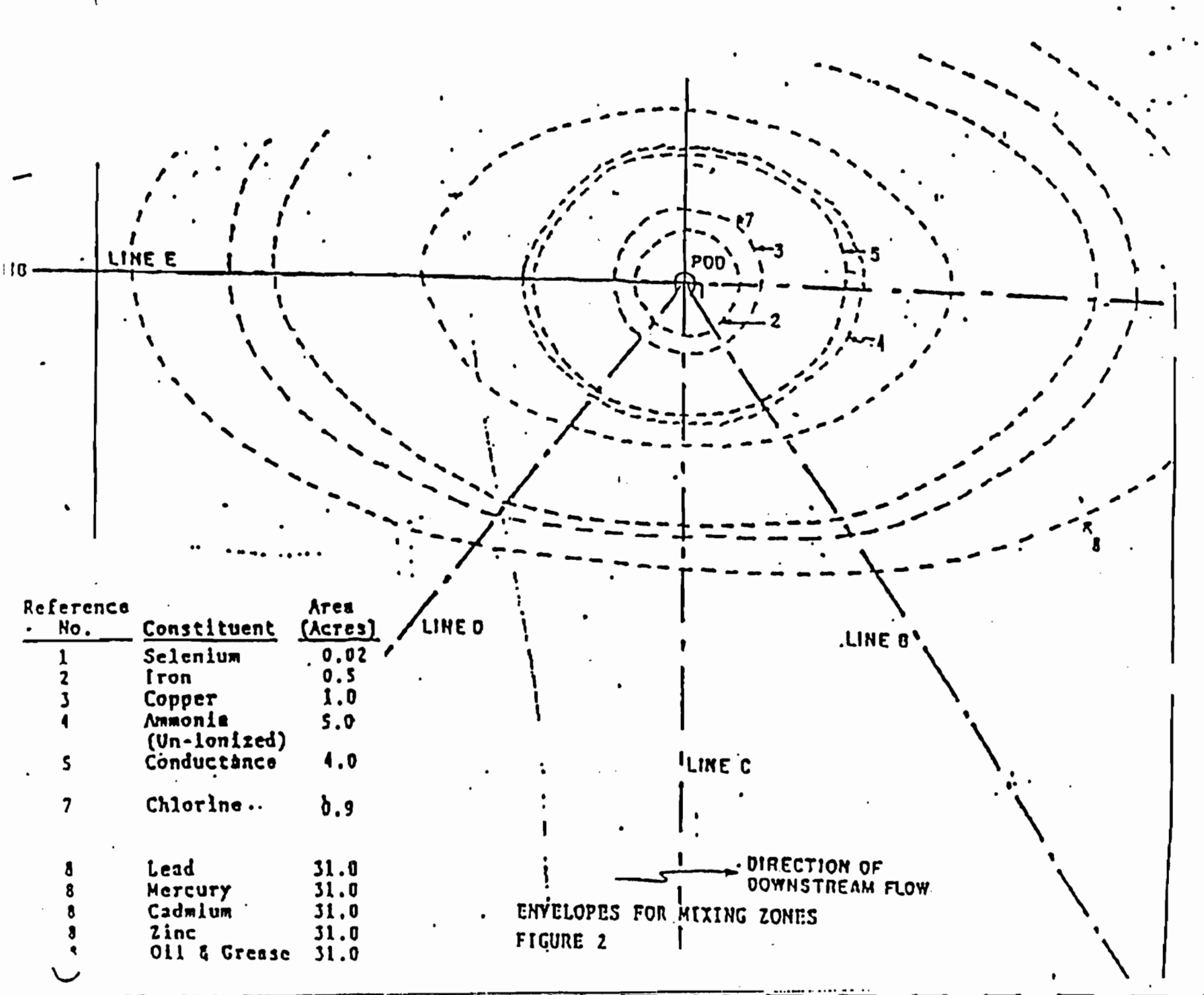
The Ph of all discharges shall be such that the Ph be within the range of 6.0 to 8.5.

9. Polychlorinated Biphenyl Compounds

There shall be no net discharge of polychlorinated biphenyl compounds.

10. Mixing Zones

The discharge of the following pollutants shall not violate the Water Quality Standards of Chapter 62-302, F.A.C. beyond the edge of the designated instantaneous mixing zone as described herein and located within the envelopes as shown on Figure 2.



Reference No.	Constituent	Area (Acres)
1	Selenium	0.02
2	Iron	0.5
3	Copper	1.0
4	Ammonia (Un-ionized)	5.0
5	Conductance	4.0
7	Chlorine	0.9
8	Lead	31.0
8	Mercury	31.0
8	Cadmium	31.0
8	Zinc	31.0
8	Oil & Grease	31.0

ENVELOPES FOR MIXING ZONES
FIGURE 2

Pollutants	Instantaneous Mixing Zone	Envelope of Mixing Zones	
Ammonia	10,000 ft^2	20.235 m^2	5.0 Acres
Arsenic	8 ft^2	65 m^2	0.2 Acres
Chlorine	750 ft^2	3,654 m^2	0.9 Acres
Copper	1,000 ft^2	4,047 m^2	1.0 Acres
Iron	400 ft^2	2,024 m^2	0.5 Acres
Selenium	10 ft^2	84 m^2	0.02 Acres
Specific Conductance	8,015 ft^2	16,188 m^2	4.0 Acres
Lead		125,600 m^2	31 Acres
Mercury		125,600 m^2	31 Acres
Cadmium		125,600 m^2	31 Acres
Zinc		125,600 m^2	31 Acres
Oil and Grease		125,600 m^2	31 Acres
Chromium	25 ft^2	195 m^2	0.05 Acres

11. Variances to Water Quality Standards

In accordance with the provisions of Sections 403.201 and 403.511(2), F.S., Seminole Electric Cooperative, Inc., is hereby granted variances to the Water Quality Standards of Chapter 62-302, F.A.C., for cadmium, lead, mercury, and zinc, but only at such times as the natural background levels of the St. Johns River approach or exceed those standards; in any event, the discharge shall comply with the effluent limitations set forth in paragraph II.A.12.a.

12. Effluent Limitations

a. The following instantaneous maximum effluent limitations shall apply for

cadmium, mercury, lead and zinc at the locations specified:

(i) Cooling blowdown - concentrations shall not exceed four times the concentrations present in the river at Applicant's intake structure at the time of intake, or not exceed Class III surface water quality standards, whichever is higher.

b. The following instantaneous maximum effluent limitations shall apply to the discharge from the chemical wastewater treatment facility:

Pollutant	Effluent Limit (mg/l)
Ammonia	28.5
Aluminum	174
Arsenic	0.073
Copper	0.66
Cyanide	0.004
Chromium	0.14
Nickel	0.09
Selenium	0.04
Oil and Grease	15

B. Water Monitoring Programs

The permittee shall monitor and report to the Department the listed parameters on the basis specified herein. The methods and procedures utilized shall receive written approval by the Department. The monitoring program may be reviewed annually by the Department, and a determination may be made as to the necessity and extent of continuation, and may be modified in accordance with Condition No. XXV.

1. Chemical Monitoring

The following parameters shall be monitored as shown during discharge and reported monthly to the DEP Northeast District Office:

Parameter	Location	Sample Type	Frequency
Flow Intake	Intake	Recorder	Totalizer
Flow Groundwater	Wellfield pipeline	Recorder	Totalizer
Flow, Discharge	C.T. Outfall	Recorder	Totalizer
Conductivity	C.T. Outfall	Recorder	Continuous
pH	C.T. Outfall	Multiple Grab	Weekly
Temperature	C.T. Outfall	Recorder	Continuous

Parameter	Location	Sample Type	Frequency
TSS	C.T. Outfall	Grab	Weekly
Chlorine Total Residual	C.T. Outfall	Multiple Grab	Weekly
Oil and Grease	C.T. Outfall & Intake	Grab	Weekly
Metals	C.T. Outfall, Intake & Waste Treatment Facility	Multiple Grab	Quarterly
Lead	"	"	*
Mercury	"	"	*
Cadmium	"	"	*
Zinc	"	"	*

*Weekly for the first three months, biweekly for the next three months, monthly for the next three months, then quarterly thereafter.

III. Groundwater

A. General

The use of groundwater from two wells for plant service water for Units 1 and 2 shall be minimized to the greatest extent practicable, but in no case shall exceed 3.9 mgd on a maximum daily basis or 0.85 mgd on an average annual basis.

B. Well Criteria

The submission of well logs and test results and location, design and construction of wells to provide plant service water shall be in accordance with applicable rules of the Department of Environmental Protection and the St. Johns River Water Management District (SJRWMD). Total water use per month shall be reported quarterly to SJRWMD commencing with the start of construction.

C. Water Use Restrictions

Groundwater is restricted to uses other than main steam condensing. Any change in the use of said water will require a modification of this condition.

D. Emergency Shortages

In the event an emergency water shortage should be declared pursuant to Section 373.175 or 373.246, F.S., by St. Johns River Water Management District for an area including the location of these withdrawal points, the Department, pursuant to Section 403.516, F.S., may alter, modify, or declare to be inactive, all or parts of Condition III.A.-F. An authorized Water Management District Representative, at any reasonable time, may enter the property to inspect the facilities.

E. Monitoring and Reporting

Seminole shall implement the following groundwater monitoring program:

1. Static groundwater elevations shall be monitored prior to purging the wells for sample collection. All measurements shall be referenced to NGVD at a precision of +/-0.01 foot. The results shall be logged for each monitor approved by the DEP and the St. Johns

River Management District in accordance with the schedule shown in Table 1 at the wells shown in Figure 3.

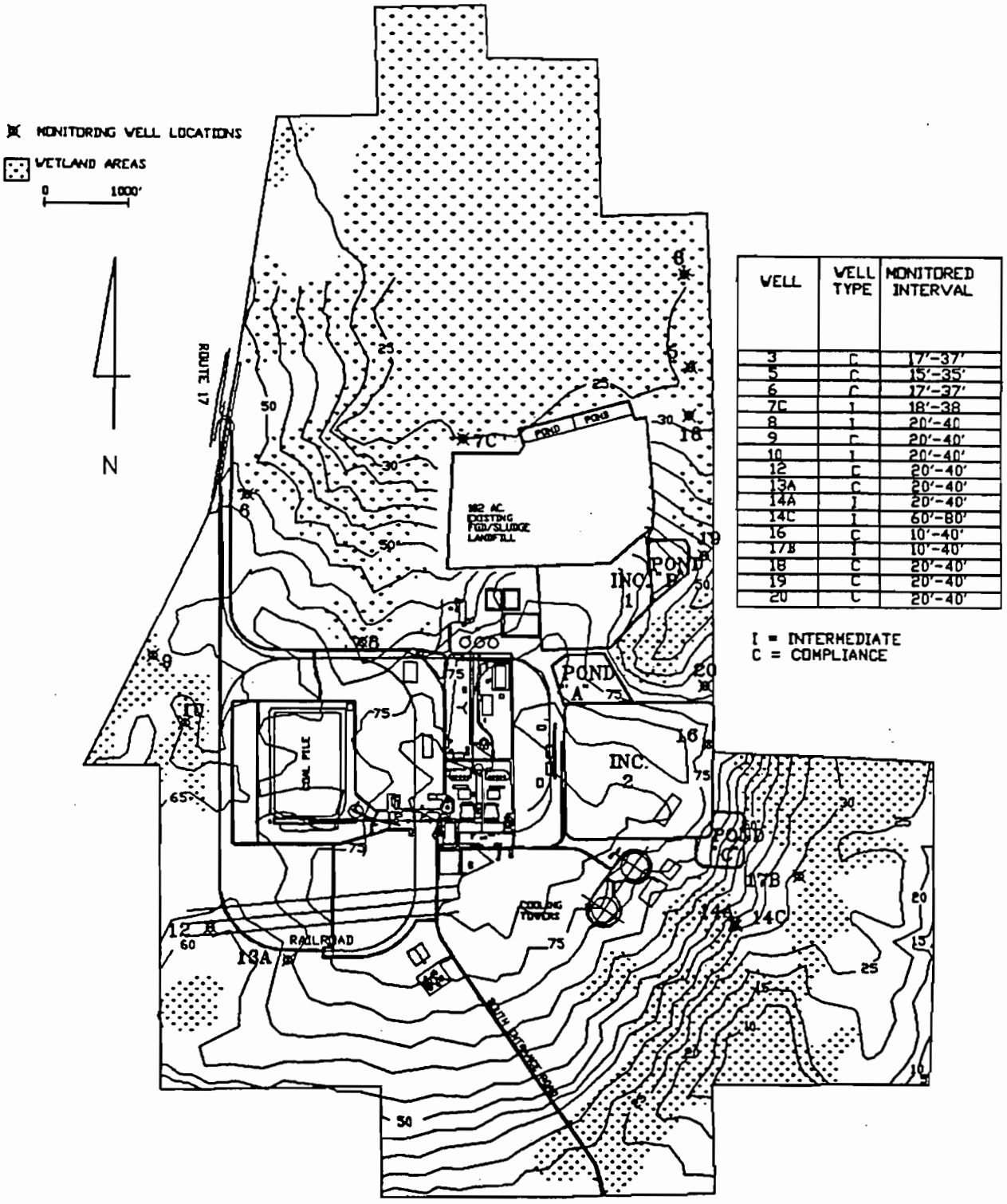
2. The Chemical analyses shall be in accord with the latest edition of Standard Methods for the Analysis of Water and Wastewater.

3. Seminole shall operate flow meters in compliance with SJRWMD specifications on all production wells.

4. After consultation with the DEP and SJRWMD, Seminole shall install a monitoring well system as generally shown in Figure 3 to monitor groundwater quality in the top 40 feet of surficial aquifer. One well shall be installed to a depth greater than 40 feet but less than 100 to monitor vertical dispersion or groundwater contaminants. Monitoring well location and designs shall be submitted to the Department and SJRWMD for review. Approval or disapproval of the locations and design shall be granted within 60 days. The water samples collected from each of the monitor wells shall be collected immediately after removal by pumping of a quantity of water equal to three well volumes and stabilization of field parameters (i.e., conductivity, temperature and pH), or five well volumes (if field parameters not monitored). The water quality analyses shall be performed monthly during the year prior to commercial operation and two years after operation and quarterly or annually thereafter in accordance with the schedule shown in Table 1. Results shall be submitted to the Department and the SJRWMD as specified in Condition III.E.9. Testing for the following constituents is required.

Conductance	Nickel
pH	Selenium
Chloride	Chromium
Iron	Arsenic
Cadmium	Beryllium
Zinc	Mercury
Copper	Lead
Sulfate	Gross Alpha
Silver	Barium

5. A scaled drawing shall be submitted which depicts the location of monitor wells in relation to property lines, facility



WELL	WELL TYPE	MONITORED INTERVAL
3	C	17'-37'
5	C	15'-35'
6	C	17'-37'
7C	I	18'-38
8	I	20'-40
9	C	20'-40'
10	I	20'-40'
12	C	20'-40'
13A	C	20'-40'
14A	I	20'-40'
14C	I	60'-80'
16	C	10'-40'
17B	I	10'-40'
18	C	20'-40'
19	C	20'-40'
20	C	20'-40'

I = INTERMEDIATE
C = COMPLIANCE

FIG. 3
GROUND WATER MONITORING PLAN

structures, roads, etc. The drawing shall include the identity of each monitor well, along with the latitude, longitude and top-of-casing elevation. The drawing shall be revised within 45 days of any new monitor well construction.

6. New monitor wells constructed after January 1, 1995, shall be installed by a Florida licensed water well contractor. Well design, installation and development shall be in accordance with A.S.T.M. standard D-5092 "Standard Practice for Design and Installation of Monitoring Wells in Aquifers", with screened intervals limited to ten feet unless otherwise approved by the Department. All monitor wells are to be permanently labeled as to identity and top-of-casing elevation.

7. Within 30 days of any new monitor well installation, a Monitor Well Completion Report, DEP Form 62-522.900(3) shall be completed and submitted.

8. In the event that a monitor well is damaged, a written report describing both the damage and proposed corrective measures shall be submitted to the DEP within 7 days. Approval shall be obtained from the Department prior to repair or replacement of any monitor well.

9. Quarterly ground water sampling and analytical reporting must be in accordance with the following schedule:

Sample Period	Report Due
1st Quarter (January-March)	April 28th
2nd Quarter (April-June)	July 28th
3rd Quarter (July-September)	October 28th
4th Quarter (October-December)	January 28th

10. Ground water analysis shall be reported on DEP Form 62-522.900(2), or a facsimile thereof. A copy of the laboratory analysis report is to accompany the completed monitoring report form.

11. Commencing with the first quarter of 1995, Seminole is authorized to discontinue monitoring of compliance wells 2 and 15. However, SECI shall monitor data collected at intermediate wells 7C and 14A to determine if

a trend or trends exist indicating that maximum contaminant levels found in 62-550 F.A.C., for the parameters listed in Condition III.B.4. may be exceeded at the boundary of the zone of discharge. DEP may require resumption of quarterly monitoring at either well 2 or 15, as appropriate, upon determining that such maximum contaminant level trends are occurring for specific parameters in wells 7C or 14A.

12. An analysis shall be conducted once every 5 years on the effluent(s) which are discharged to ground water via the percolation ponds. The analysis shall be run on a 24-hour flow-proportioned sample for the priority pollutants (excluding pesticides).

13. After the second year of monitoring and periodically thereafter, the Department and the applicant shall review the results of the monitoring program and determine the necessity for modifying or continuing the program.

F. Leachate

1. Zone of Discharge

Leachate from the FGD/sludge landfill, coal storage pile, bottom ash sump, percolation and FGD emergency pond shall not contaminate waters of the State (including both surface and groundwaters) in excess of the limitations of Chapter 62-520, F.A.C., beyond the boundary of the site.

2. Corrective Action

When the groundwater monitoring system show a violation of the groundwater water quality standards of Chapter 62-520, the appropriate ponds, FGD landfill, or coal pile shall be sealed, relocated or closed, or the operation of the affected facility shall be altered in such a manner as to assure the Department that no violation of the groundwater standards will occur beyond the boundary of the site.

Table I Groundwater Monitoring Frequency

	FGD Area Wells 3,5,7C,18,19,20		Coal Pile Area Wells 6,8,9,10,12,13A		Perc Pond Area Wells 14A,14C,16,17B	
	Monthly	Quarterly	Monthly	Yearly	Monthly	Quarterly
Conductance	X	X	X	X	X	X
pH	X	X		X	X	X
Chloride	X	X		X	X	X
Sulfate	X	X		X	X	X
Cadmium		X		X		X
Zinc	X	X		X	X	X
Iron	X	X	X	X	X	X
Copper		X		X		X
Silver		X		X		X
Nickel		X		X		X
Selenium	X	X		X	X	X
Chromium		X		X		X
Beryllium		X		X		X
Mercury	X	X		X	X	X
Lead		X		X		X
Barium		X		X		X
Arsenic	X	X		X	X	X
Gross Alpha		X		X		X

IV. Control Measures During Construction

A. Stormwater Runoff

During construction and plant operation, necessary measures shall be used to settle, filter, treat or absorb silt containing or pollutant laden stormwater runoff to limit the suspended solids to 50 mg/l or less at the POD during rainfall periods less than the 10-year, 24-your rainfall, and to prevent an increase in turbidity of more than 50 Jackson Turbidity Units above background in waters of the state beyond 150 meters from the POD.

Control measures shall consist at the minimum, of filters, sediment traps, barriers, berms or vegetative planting. Exposed or disturbed soil shall be protected as soon as possible to minimize silt and sediment laden runoff. The pH shall be kept within the range of 6.0 to 8.5 at the POD.

B. Sanitary Wastes

Disposal of sanitary wastes from construction toilet facilities shall be in accordance with applicable regulations of the Department and appropriate local health agency. The sewage treatment plant shall be operated in accordance with Chapters 62-302, 62-601 and 17-602, F.A.C. Plans and specifications for the sewage treatment plant shall be submitted to the Department's St. Johns River Subdistrict Manager for review and approval prior to installation.

C. Environmental Control Program

An environmental control program shall be established under the supervision of a qualified person to assure that all construction activities conform to good environmental practices and the applicable conditions of certification. The permittee shall notify the Department if unexpected harmful effects or evidence of irreversible environmental damage are detected during construction, shall immediately report to the Department and shall within two weeks provide an analyses of the problem and a plan to eliminate or significantly reduce the harmful effects or damage, and to prevent reoccurrence.

V. Solid Wastes

Solid Wastes resulting from construction or operation shall be disposed of in accordance with the applicable regulations of Chapter 62-701, F.A.C. The permittee shall submit a program for approval but outlining the methods to be used in handling and disposal of solid wastes indicating at least methods for erosion control, covering, vegetation and quality control.

Open burning in connection with land clearing shall be in accordance with Chapter 62-256, F.A.C. No additional permits shall be required, but the Division of Forestry shall be notified prior to burning. Open burning shall not occur if the Division of Forestry has issued a ban on burning due to fire hazard conditions.

VI. Operation Safeguards

The overall design, layout, and operation of the facilities shall be such as to minimize hazards to humans and the environment. Security control measures shall be utilized to prevent exposure of the public to hazardous conditions. The Federal Occupational Safety and Health Standards will be complied with during construction and operation. The Safety Standards specified under Section 440.56, F.S., by the Industrial Safety Section of the Florida Department of Commerce will also be complied with.

VII. Screening

The permittee shall provide screening of the site through the use of aesthetically acceptable structures, vegetated earthen walls and/or existing or planted vegetation.

VIII. Potable Water Supply System

The potable water supply system shall be designed and operated in conformance with Chapters 62-550, 62-551, 62-555, and 62-560, F.A.C. Information as required in Chapters 62-550, 62-551, 62-555, and 62-560 F.A.C., shall be submitted to the Department prior to construction and operation. The operation of the potable water supply system shall be certified in accordance with Chapters 62-602 and 62-699, F.A.C.

IX. Transformer and Electric Switching Gear

The foundations for transformers, capacitors, and switching gear necessary for Seminole Units 1 and 2 to connect with the existing transmission/distribution

system shall be constructed of an impervious material and shall be constructed in such a manner to allow complete collection and recovery of any spills or leakage of oily, toxic, or hazardous substances.

X. Toxic, Deleterious, or Hazardous Materials

The spill of any toxic, deleterious, or hazardous materials shall be reported in the manner specified by Condition XV.

XI. Construction and Maintenance Activities in Waters of the State.

1. No construction on sovereignty submerged lands shall commence without obtaining lease or title from the Trustees of the Internal Improvement Trust Fund.

2. Construction and maintenace of intake and discharge structures should be done in a manner to minimize turbidity. Turbidity screens should be used to prevent turbidity in excess of 29 NTU above background beyond 150 meters from the dredging, pile driving or construction site.

3. Dredging of the intake channel and discharge pipe trench should be performed by hydraulic dredge (small "mudcat" type is suitable): clamshell or other excavating equipment is satisfactory behind cofferdams or other turbidity control devices.

4. All spoil shall be piped hydraulically or trucked to an upland disposal site of sufficient capacity to retain all material. The discharge pipe trench should be refilled with clean sand sized material.

5. Effective stabilization of submerged bottom sediments at the discharge pipe exits should be achieved and maintained during the period of operation by the placement of riprap or other suitable material.

XII. FGD/Sludge Landfill and Coal Pile

Adequate geophysical testing for landfill increments 1 and 2 shall be conducted in accordance with Chapter 62-701 F.A.C.

The existing and proposed FGD sludge landfill areas shall be monitored and studied pursuant to a detailed

groundwater testing and monitoring program as defined in Condition III.E.

The results of the program will be used by the Department in determining whether Seminole has affirmatively demonstrated that Florida Water Quality Standards (62-520, F.A.C.) will not be violated beyond the site boundary.

If the Department determines that Seminole has failed to affirmatively demonstrate that Florida Water Quality Standards (Chapter 62-520 F.A.C.) will not be violated, Seminole shall present to the Department, within 90 days of such determination, a plan of correction, (which may include, if appropriate, an impermeable liner) for review and approval by the Department, and for timely implementation by Seminole.

SECI is granted the authority to dispose of FGD wastes in the existing FGD/Sludge landfill by implementation of microencapsulation and/or macroencapsulation methods as described below:

a.) Microencapsulation or fixation of unoxidized FGD waste shall be accomplished by following good engineering practices and applicable environmental standards. The fixated material shall achieve an ultimate permeability of no greater than 7×10^{-7} cm/sec.

b.) Macroencapsulation of physically stabilized unoxidized FGD waste shall be accomplished by following good engineering practices and applicable environmental standards. The macroencapsulation cells shall be constructed on an initial bed of fixated material measuring a minimum of 8.0 feet thick and having an ultimate permeability of 7×10^{-7} cm/sec. An open cell design configuration with a gradually sloped bottom shall be constructed to allow the stabilized FGD material to drain and minimize the potential of developing a hydraulic head. The cell walls and cap shall be constructed of fixated material having an ultimate permeability no greater than 7×10^{-7} cm/sec. The cells shall be filled with physically stabilized FGD material to the full vertical extent and shall be capped with 5.0 feet of fixated material as the cells develop.

c.) A quality control program shall insure that the permeability of the fixated FGD material does not exceed prescribed levels. Perimeter berms, swales,

and ponds constructed of fixated FGD material may be used to capture, route, and contain all runoff from the landfill area within the closed FGD scrubber/wastewater recycling system.

SECI is authorized to continue these FGD/Sludge disposal activities in the areas designated as Landfill Increment 1 and Landfill Increment 2 as shown in attached Figure 4 provided:

a. SECI shall provide three sets of the final landfill construction drawings and retention pond design calculations to the Florida Department of Environmental Protection, Siting Coordinator, for review and approval prior to construction of landfill Increments 1 & 2 shown in attached Figure 4.

b. Prior to finalizing the construction plans for Landfill Increments 1 & 2, SECI shall apply for and receive a binding jurisdictional determination from the Department, which delineates the boundaries of any wetlands adjacent to landfill increments. SECI shall notify the Siting Coordination Office of the submittal of the application for the binding determination and when the determination is granted.

c. If the binding jurisdiction determination required above shows that the proposed construction will occur in wetlands, SECI shall provide the Siting Coordination Office with complete post-certification information regarding the wetland impacts, including a joint application form and detailed drawings of the proposed work. The Department shall bave 30 days to review the information for sufficiency and request additional information as needed. If the Department, determined that it is necessary, SECI shall provide mitigation to offset the wetland impacts of the project. Once the information is sufficient, the Department shall have 90 days to issue a determination of compliance of the project.

d. With regard to the existing FGD/Sludge landfill and Increments 1 & 2, Seminole may construct the landfill and appurtenant facilities and may dispose of solid waste within 200 feet of any natural or artificial body of water, including wetlands with the jurisdiction of the Department, pursuant to Rule 62-701.300(2)(g).

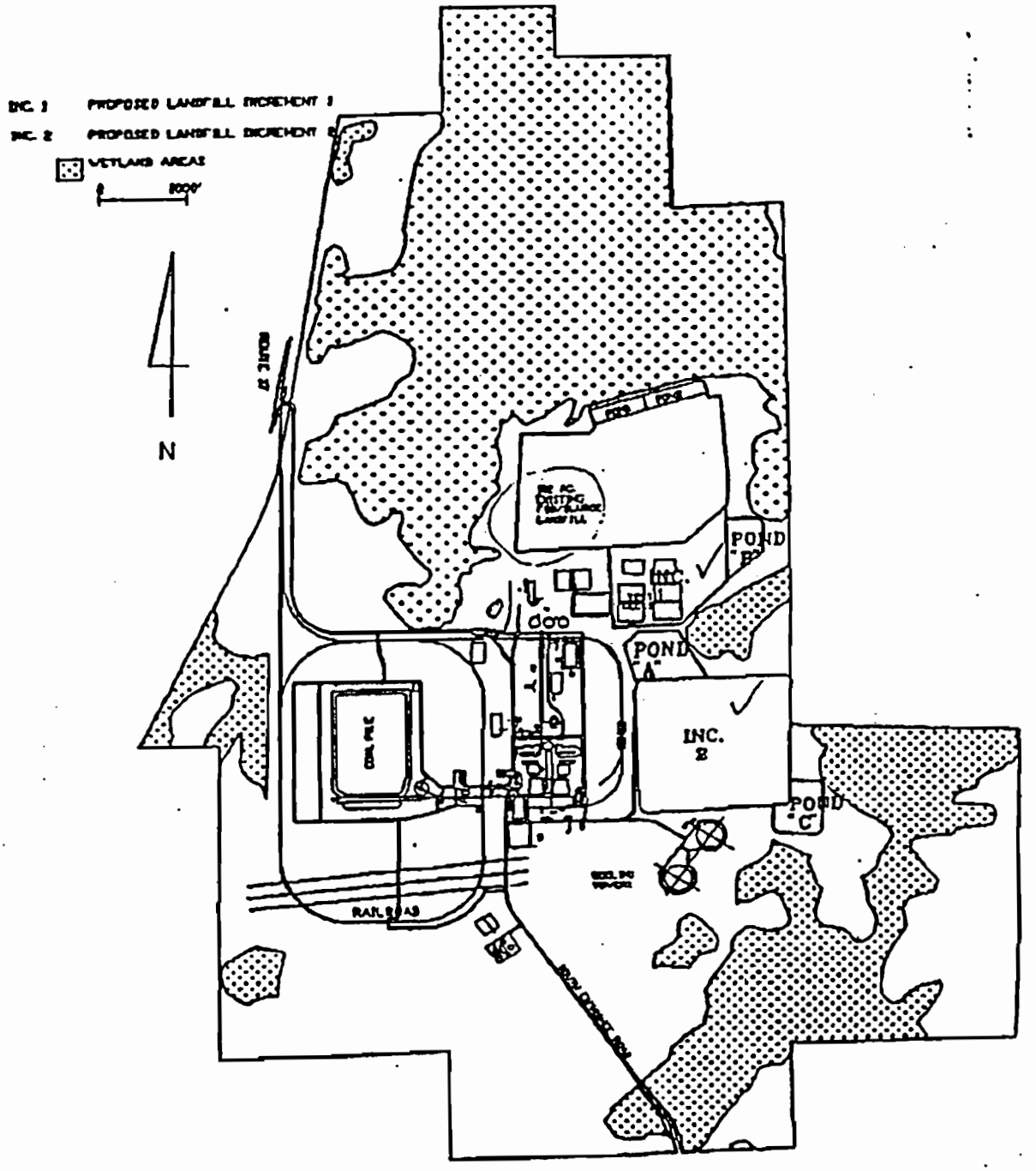


FIGURE 4

FGD/SLUDGE LANDFILL LIMITS

XIII. Transmission Lines

Directly associated transmission lines shall be constructed and maintained in a manner to minimize environmental impacts in accordance with Chapter 403, F.S.

A. Construction

1. Filling and construction in waters of the State shall be minimized to the extent practicable. No such activities shall take place without obtaining lease or title from the Trustees of the Internal Improvement Trust Fund.

2. Placement of fill in wetland areas shall be minimized by spanning such areas with the maximum transmission lines span practicable.

3. Construction and access roads should avoid wetlands and be located in surrounding uplands. Any fill required in wetlands for construction but not required for maintenance purposes shall be removed and the ground restored to its original contours after transmission line placement.

4. Keyhole fills from upland areas are preferable to a single road and should be oriented as nearly parallel to surface water flow lines as possible.

5. Sufficient culverts shall be placed through fill causeways to maintain sheet flow. The number and locations of such culverts will be determined in the field by consultation with DEP field inspectors.

6. Maintenance roads shall be planted with native species to prevent erosion and subsequent water quality degradation.

7. Construction activities should proceed as much as possible during the dry season.

8. Turbidity control measures, where needed, shall be employed to prevent violation of water quality standards.

9. Good environmental practices as described in Environmental Criteria for Electric

Transmission Systems as published by the U.S. Department of Interior and the U.S. Department of Agriculture should be followed.

10. Any archaeological sites discovered during construction of the transmission lines shall be disturbed as little as possible and such discovery shall be communicated to the Department of State, Division of Archives, History and Records Management.

B. Maintenance

1. Vegetative removal for maintenance should be carried out in the following manner:

Vegetative clearing operations to be carried out within the corridor should follow the general standards for clearing rights-of-way for overhead transmission lines and follow good environmental practices as described in *environmental criteria for Electric* Transmission Systems, as published by The U.S. Department of the Interior and The U.S. Department of Agriculture, thus preserving immature tree species along the peripheries of the right-of-way. These standards define the zone that shall be cleared of all tree growth as the area between structures 10 ft. to either side of the outside conductor. The remainder of the right-of-way from the cleared area to the right-of-way limit shall be screened. This translates to mean that only trees in excess of 10 ft. in height would be removed from the outer zone except where location of the access roads necessitates complete clearing.

2. Approved Chemicals or herbicides may be used for vegetation control along the transmission line without prior approval of the Department.

XIV. Change in Discharge

All discharges or emission authorized herein shall be consistent with the terms and conditions of this certification. The discharge of any pollutant not identified in the application, or any discharge more frequent than, or at a level in excess of that authorized herein, shall constitute a violation of the certification. Any anticipated facility expansions, production increases, or process modification which will

result in new, different or increased discharges or expansion in steam generating capacity will require a submission of a new or supplemental application pursuant to Chapter 403, Florida Statutes.

XV. Noncompliance Notification

If, for any reason, the permittee does not comply with or will be unable to comply with any limitation specified in this certification, the permittee shall notify the Director of District Management for the Northeast District of the Department by telephone during the working day during which permittee becomes aware of said noncompliance and shall confirm this situation in writing within seventy-two (72) hours of first becoming aware of such conditions, supplying the following information:

a. A description and cause of noncompliance; and

b. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being take to reduce, eliminate and prevent recurrence of the noncomplying event.

XVI. Facilities Operation

The permittee shall at all times maintain in good working order and operate as efficiently as possible all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this certification. Such systems are not to be bypassed without prior department approval, except, during periods when light oil is used for ignition, the FGD system may be bypassed.

XVII. Adverse Impact

The permittee shall take all reasonable steps to minimize any adverse impact resulting from noncompliance with any limitation specified in this certification, including but not limited to such accelerated or additional monitoring as necessary to determine the nature and impact of then on complying event.

XVIII. Right of Entry

The permittee shall allow the Secretary of the Florida Department of Environmental Protection and/or authorized representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises where an effluent source is located or in which records are required to be kept under the terms and conditions of this permit; and

b. To have access to and copy all records required to be kept under the conditions of this certification; and

c. To inspect and test any monitoring equipment or monitoring method required in this certification and to sample any discharge or pollutants, and

d. To assess any damage to the environment or violation of ambient standards.

XIX. Revocation or Suspension

This certification may be suspended or revoked pursuant to Section 403.512, Florida Statutes, or for violations of any Condition or certification.

XX. Civil and Criminal Liability

This certification does not relieve the permittee from civil or criminal responsibility or liability for noncompliance with any conditions of this certification, applicable rules or regulations of the Department, or Chapter 403, Florida Statutes, or regulations thereunder.

Subject to Section 403.511, Florida Statutes, this certification shall not preclude the institution of any legal action or relieve the permittee from any responsibilities or penalties established pursuant to any other applicable State Statutes or regulations.

XXI. Property Rights

The issuance of this certification does not convey any property rights in either real or personal property tangible or intangible, nor any exclusive privileges, nor does it authorize any injury to public or private property or any invasion or personal rights, nor any infringement of Federal, State or local laws or regulations. The applicant will obtain title, lease or right of use form the State of Florida, to any sovereign submerged lands occupied by the plant, transmission line structures, or appurtenant facilities.

XXII. Severability

The provisions of this certification are severable, and if any provision of this certification, or the application of any provision of this certification to any circumstances is held invalid, the application of such provision to other circumstances and the remainder of the certification shall not be affected thereby.

XXIII. Definitions

The meaning of terms used herein shall be governed by the definitions contained in Chapter 403, Florida Statutes, and any regulation adopted pursuant thereto. In the event of any dispute over the meaning of a term used in these general or special conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative by the use of the commonly accepted meaning as determined by the Department.

XXIV. Review of Site Certification

The certification shall be final unless revised, revoked or suspended pursuant to law. At least every five years from the date of issuance of this certification or any National Pollutant Discharge Elimination System Permit issued pursuant to the Federal Water Pollution Control Act Amendments of 1972, for the plant units, the Department shall review all monitoring data that has been submitted to it during the preceding five-year period, for the purposes of determining the extent of the permittee's compliance with the conditions of this certification of the environmental impact of this facility. The Department shall submit the results of its review and recommendations to the permittee. Such results will be repeated at least every five years thereafter.

XXV. Modification of Conditions

The conditions of this certification may be modified in the following manner:

a. The Board hereby delegates to the Secretary the authority to modify, after notice and opportunity for hearing, any conditions pertaining to monitoring, testing and evaluation programs, sampling, groundwater, mixing zones, zones of discharge or variances to water quality standards,

or location of transmission line corridors within areas already approved at the land use hearing.

b. All other modifications shall be made in accordance with Section 403.516, Florida Statutes.

XXVI. Rail Car Maintenance Facility

The rail car maintenance and surface coating facility shall be designed, constructed and operated in conformance with chapters 62-296, 62-25, and 62-302, F.A.C. and the following limitations:

A. Visible Emissions - shall not exceed 20% opacity.

B. VOC Emissions - shall not exceed 38.75 lbs/hr. or 11.84 T/year.

C. Particulate Emissions - Unconfined particulate emissions from abrasive blasting shall be controlled as required by Section 62-296.310(3)(c), F.A.C., using the following precautions:

1. The cover and the partial enclosure of the shelter shall act as a windbreak to minimize the amount of residual particulate that becomes airborne.

2. Containment screens shall be installed on the northern and southern ends of the shelter.

D. Stormwater Runoff - shall be collected in existing runoff ditches and routed to percolation/evaporation areas on site.

E. Wastewater - There shall be no discharge of wastewater from the maintenance facility site.

F. Sanitary Waste - Shall be disposed of in accordance with the applicable substantive requirements of chapter 10D-6, F.A.C.

G. Water - The associated drinking water system shall comply with the substantive requirements of chapters 10D-4, 62-550 and 62-555, F.A.C. Consumptive use of groundwater shall be governed by the non-procedural provisions of 40C-2.381, F.A.C. and Section 18.0.1, Part III, "Applicants Handbook Consumptive Uses of Water."

H. Spent Blast Media - Spent blast media associated with the railcar maintenance facility shall be

containerized during storage and transportation and subsequently disposed of in the onsite FGD/sludge landfill.

R. Clarke

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30308

AUG 09 1979

REC'D AUG 13 1979

PSD Permit
Final Determination

126-E.3A.3

REF: 4PM-AP

Mr. T. E. Crudlish
Project Director
Seminole Electric Cooperative, Inc.
Suite 100
7210 East Busch Boulevard
Tampa, Florida 33612

Dear Mr. Crudlish:

Review of your December 15, 1978 application to construct two (2) Hayatt peter boilers near Palatka, Florida has been completed. The construction is subject to rules for the Prevention of Significant Air Quality Deterioration (PSD), contained in 40 CFR 52.21.

We have determined that the construction as described in the application meets all applicable requirements of the PSD regulations, subject to the conditions in the Final Determination (enclosed). This office performed a Preliminary Determination concerning the proposed construction, and published a request for public comment on February 2, 1979. A public hearing was held on June 4, 1979. Comments received were relayed to your office. Your comments, as well as other written comments and those voiced at the public hearing, were addressed in the Final Determination. Authority to Construct a Stationary Source is hereby issued for the facility described above, subject to the conditions in the Final Determination. This Authority to Construct is based solely on the requirements of 40 CFR 52.21, the federal regulation governing significant deterioration of air quality. It does not apply to NPDES or other permits issued by this agency or permits issued by other agencies. Information regarding EPA permitting requirements can be provided if you contact Mr. Joe Franzmathes, Director, Office of Program Integration and Operations, at 404/881-4727. Additionally, construction covered by this Authority to Construct must commence within 18 months from the receipt of this letter.

The United States Court of Appeals for the D. C. Circuit has issued a ruling in the case of Alabama Power Co. vs. Douglas M. Costle (7?-1??? and consolidated cases) which has significant impact on the EPA prevention of significant deterioration (PSD) program and permits issued thereunder. Although the court has stayed its decision pending resolution of petitions for reconsideration, it is possible that the final decision will require modification of the PSD regulations and could affect permits issued under the existing program. Examples of potential impact areas include the scope of best available control technology (BACT), source applicability, the amount of increment available (baseline definition), and the extent of preconstruction monitoring that a source may be required to perform. The applicant is hereby advised that this permit may be subject to reevaluation as a result of the final court decision and its ultimate effect.

Please be advised that a violation of any condition issued as part of this approval, as well as any construction which proceeds in material variance with information submitted in your application, will be subject to enforcement action.

Authority to Construct will take effect on the date of this letter. The complete analysis which justifies this approval has been fully documented for future reference, if necessary. Any questions concerning this approval may be directed to Mr. Roy Cunningham, Chief, Air Strategy Development Section (404/881-3286).

Sincerely yours,

Thomas W. Devine, Director
Air & Hazardous Materials Division

Enclosure

cc: Mr. J.P. Subramani, Chief
Bureau of Air Quality Management
Florida Department of Environmental Regulation

AAA
RC
TEC
RP
JD

PERMIT: PSD

STATUTORY MANDATE: Clean Air Act (§§ 160-169)

ADMINISTERING AGENCY: EPA

APPROVAL DATE: August 13, 1979

COMMENTS: None

Review of a Proposed Air Pollution Source Pursuant to Environmental Protection Agency Rules for the Prevention of Significant Deterioration (PSD)

40 CFR 52.21

Seminole Electric Cooperative, Inc.

Seminole Plant Units No. 1 and No. 2
Putnam County, Florida

Final Determination

U.S. Environmental Protection Agency
345 Courtland Street, N.E.
Atlanta, Georgia 30308

I. Introduction

Seminole Electric Cooperative, Inc., has applied to the U.S. Environmental Protection Agency to construct a coal fired steam electric plant in Putnam County, Florida. The proposed construction is subject to review under 40 CFR 52.21, Regulations for the Prevention of Significant Deterioration (PSD). Under these regulations, a new source of air pollution in any one of 28 specified categories which will emit more than 100 tons per year of any pollutant, is subject to review for each of those pollutants. One of these categories is fossil fuel-fired steam electric plants of more than 250 million BTU per hour heat input, of which Seminole Plant is one.

Paragraph (r) of the PSD regulations requires, in part, that EPA issue a Final Determination whether the source should be approved, approved with conditions, or disapproved. It is the decision of EPA that the source should be approved with conditions. The conditions are included to insure that the applicant complies with emission control techniques and emission limits which are a part of the application. The conditions of approval follow on the next page.

Conditions of Approval

A. FOR THE ELECTRIC UTILITY STEAM GENERATING UNITS

The applicant shall comply with emission limits and other requirements as specified by the U.S. Environmental Protection Agency's Standards of Performance for Electric Utility Steam Generating Units promulgated on June 11, 1979 (40 CFR 60, Subpart Da). Emission limits for particulate matter, sulfur dioxide and nitrogen oxides are specified below:

Item 1 - Particulate matter

(a) Particulate matter in gases discharged into the atmosphere from the steam generators shall not exceed 13 ng/J (0.03 lb/million Btu) heat input.

(b) Gases discharged into the atmosphere from the steam generators shall not exhibit greater than 20 percent opacity except for one 6 minute period per hour of not more than 27 percent opacity.

Item 2 - Sulfur Dioxide

(a) While combusting coal in the steam generating units, sulfur dioxide in gases discharged into the atmosphere from the steam generators shall not exceed:

1. 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

2. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) While combusting oil in the steam generating units, sulfur dioxide in gases discharged into the atmosphere from the steam generators shall not exceed:

1. 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

2. 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) For purposes of determining compliance with provisions of paragraphs (a) and (b) of this section, any reduction in potential sulfur dioxide emissions resulting from the following may be credited in accordance with 40 CFR 60.48a(b):

(1) Fuel pretreatment.
(2) Coal pulverizers.
(3) Bottom ash and fly ash interaction.

(d) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$PS_{SO_2} = x(340) + y(520)/100$
where:

PS_{SO_2} is the prorated standard for sulfur dioxide when combusting different fuels simultaneously (ng/J heat input).

x is the percentage of total heat input derived from the combustion of fuel oil.

y is the percentage of total heat input derived from the combustion of coal.

(e) Condition (b) regarding SO_2 percent reductions does not apply during combustion of oil since fuel oil is to be combusted only during periods of ignition startup, and not as a supplemental fuel during other modes of operation.

Item 3 - Nitrogen Oxide Emissions

(a) Nitrogen oxides in gases discharged into the atmosphere from the steam generators shall not exceed:

1. 130 ng/J heat input (0.3 lb/million Btu) derived from the combustion of fuel oil.

2. 260 ng/J heat input (0.6 lb/million Btu) derived from the combustion of bituminous coal.

(b) When both fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$PSno_x = x(130)+y(260)/100$$

Where:

$PSno_x$ is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input):

x is the percentage of total heat input derived from the combustion of fuel oils.

y is the percentage of total heat input derived from the combustion of bituminous coal.

B. FOR THE COAL PREPARATION AND MATERIALS HANDLING FACILITIES

For the coal preparation facilities, the applicant must meet requirements as specified by the U.S. Environmental Protection Agency's Standards of Performance for Coal Preparation Plants promulgated on January 15, 1976 (40 CFR 60, Subpart Y). Opacity requirements for these and other materials handling facilities are specified below.

Item 1

The applicant shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, coal transfer and loading system, or any other materials handling system, except lime and limestone processing and handling, gases which exhibit 20 percent opacity or greater.

Item 2

The applicant shall not cause to be discharged into the atmosphere from any lime or limestone processing or handling facilities, gases containing particulate matter in excess of 0.02 gr/dscf, as measured by EPA Method 5, 40 CFR 60 Appendix A. Performance tests, if required by the Administrator, shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified by EPA. For the purpose of determining compliance with the emission limit, the arithmetic mean of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

C. SUBMISSION OF FINAL DESIGN SPECIFICATIONS TO EPA

The applicant will submit to EPA copies of the Inquiries for Electrostatic Precipitator (ESP) and Flue Gas Desulfurization System (FGD) at the same time they are sent to the approved bidders. EPA will advise Mr. T. E. Crumlish, expeditiously, of any concerns it has with the proposed specifications. The Applicant will incorporate appropriate EPA comments into the Inquiries, by Addendum, prior to receipt of bids if subject EPA comments are timely.

Upon receipt of the Engineer's Recommendation for Award of ESP and FGD, Applicant will forward appropriate technical and bid data of the apparent successful bidder to EPA for its determination of whether the selected control devices will be adequate to meet the emission limits specified in the approval. A list of any additional required information will be sent to the applicant upon receipt of this submittal. Although the type of control devices which are described in the application have been determined by EPA in its initial pre-construction review to be adequate, EPA must review the final selected devices and EPA may, upon review of these data, disapprove the application if EPA determines the selected control devices to be inadequate to meet the emission limits specified in this conditional approval.

II. Background

On May 19, 1978, EPA received from Mr. T.E. Crumlish an application from Seminole Electric Cooperative, Inc. to construct two 680 megawatt coal fired steam electric generators in Putnam County, Florida. Additional information was submitted from Seminole or its representatives on June 8, July 3, October 26, November 28, November 29, and December 15, 1978. Also on December 15, Seminole submitted a revision to its application which changed the proposed emission rate of sulfur dioxide from the plant. This revision was submitted in order to make the

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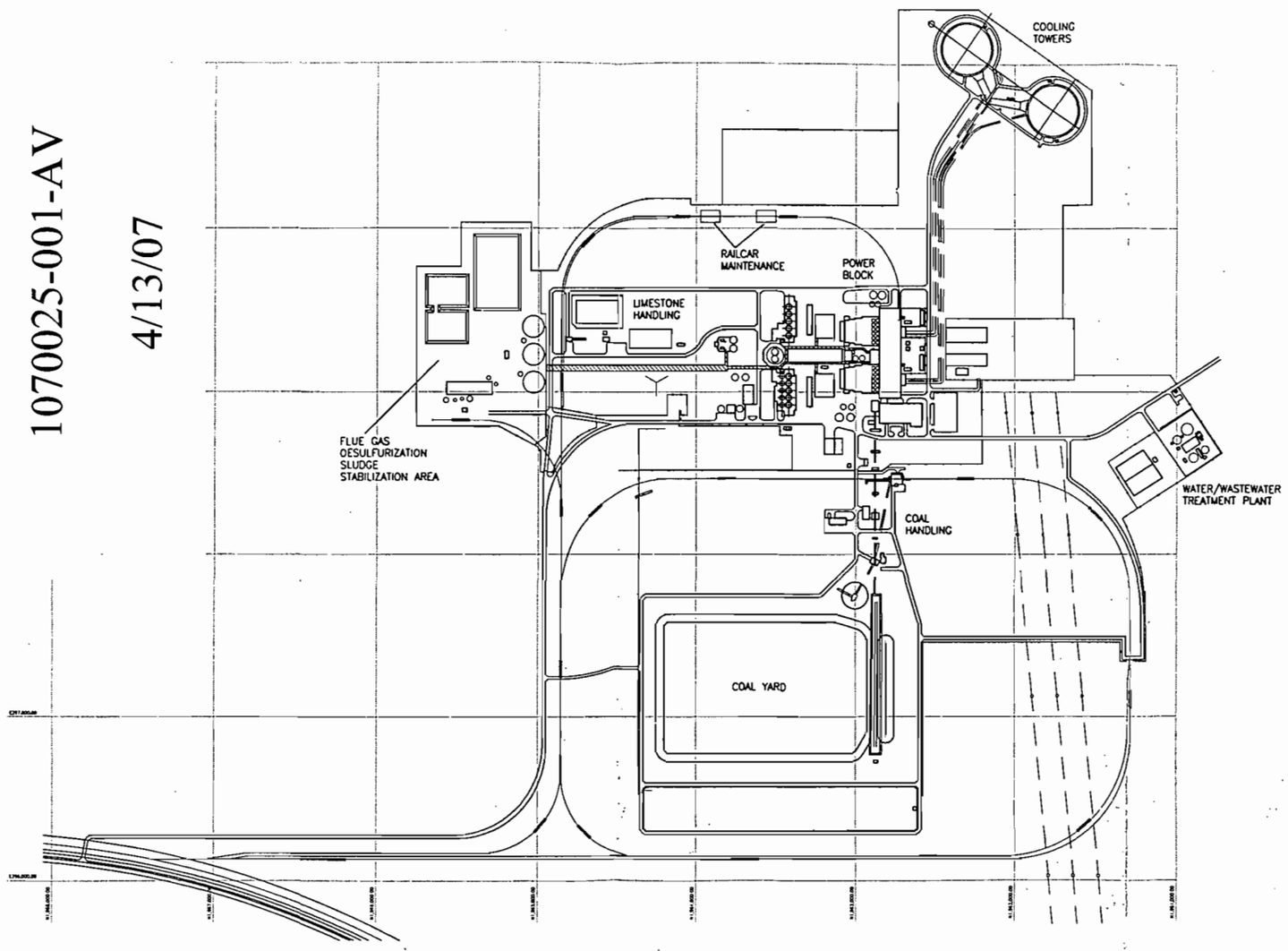

N

GRAPHIC SCALE

0 375 750

SCALE IN FEET

FIGURE II.D.2.1.

OVERALL FACILITY PLOT PLAN

Source: Seminole Electric, 1984.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

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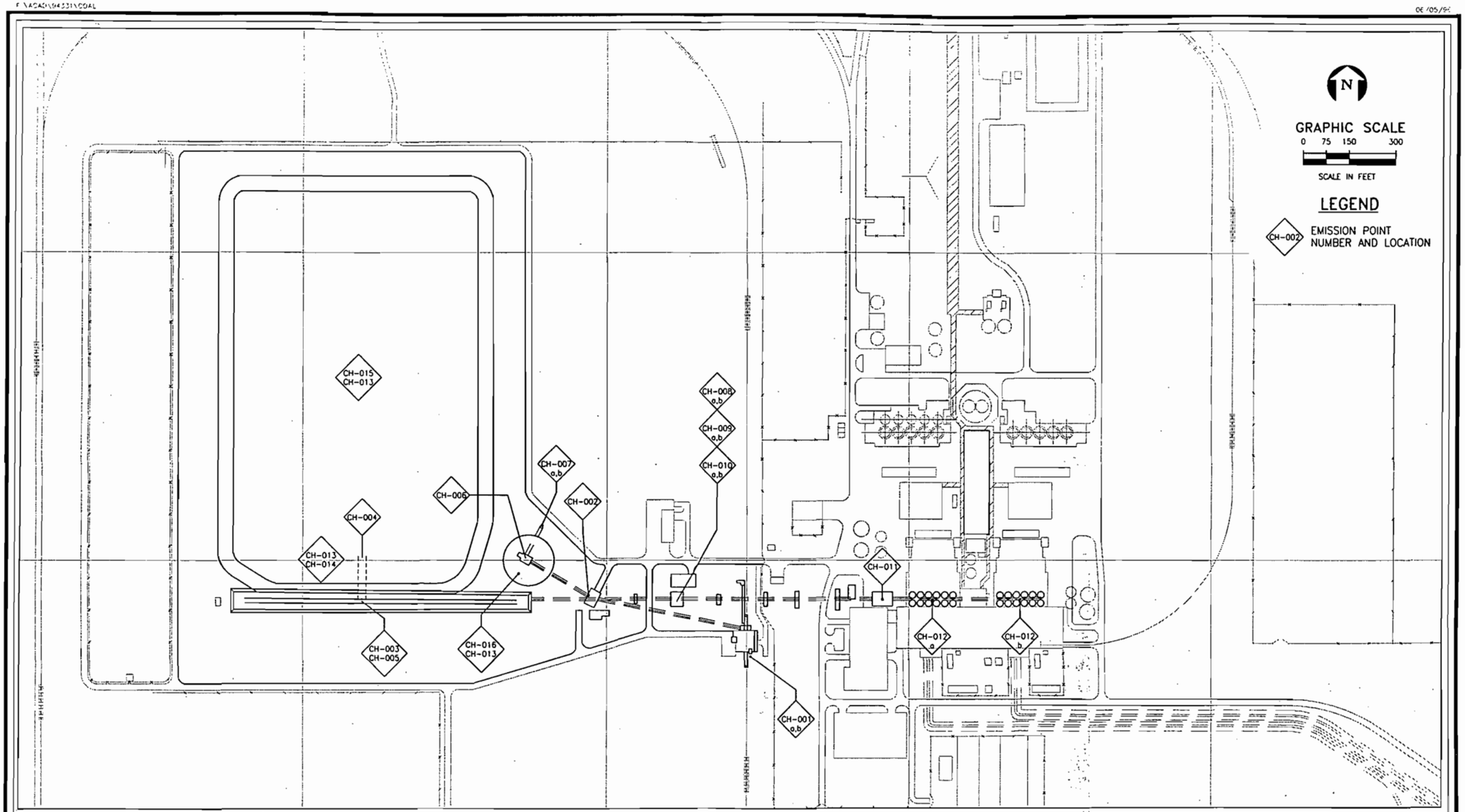

FIGURE II.D.2.2.

COAL HANDLING

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

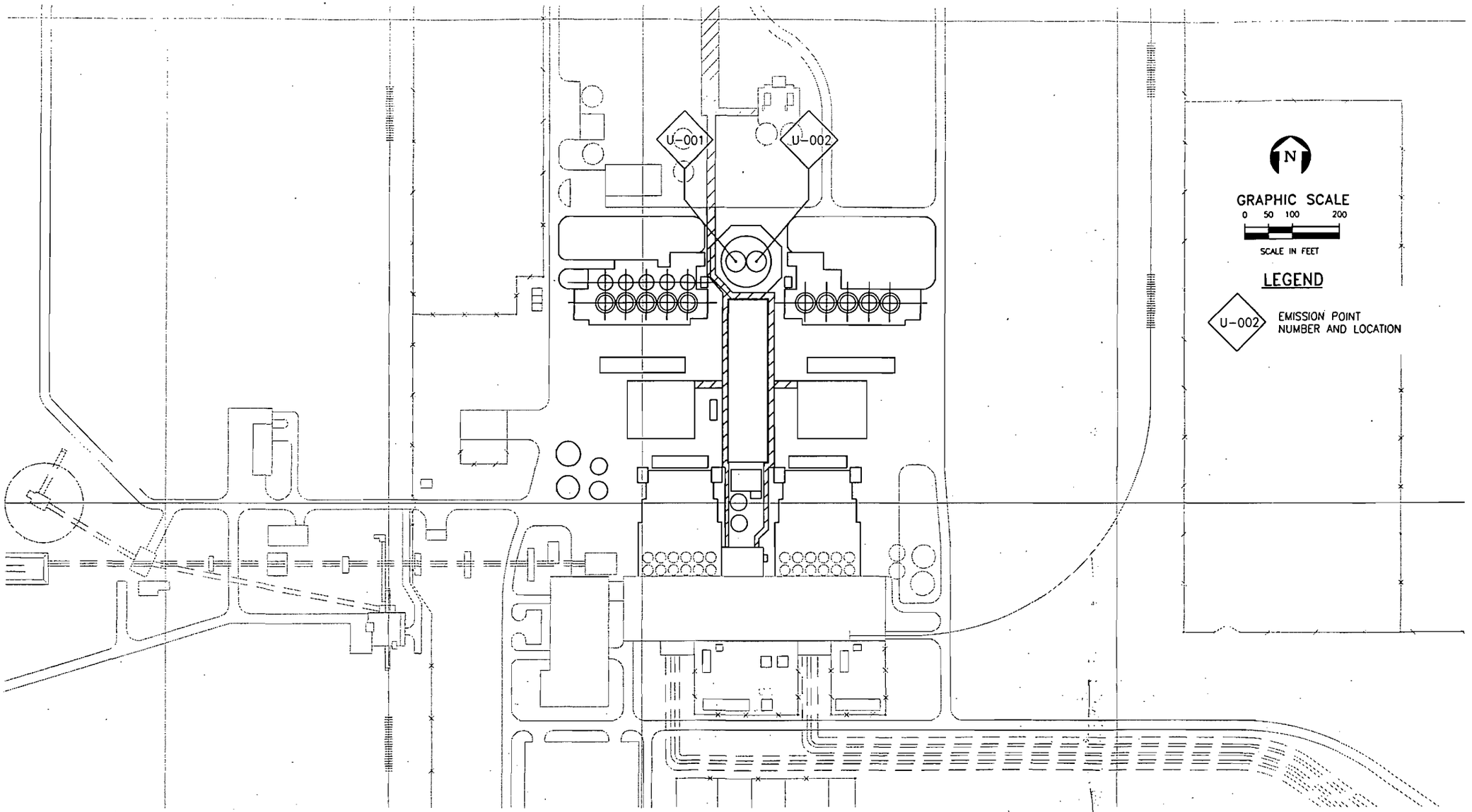

FIGURE II.D.2.3.

POWER BLOCK

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

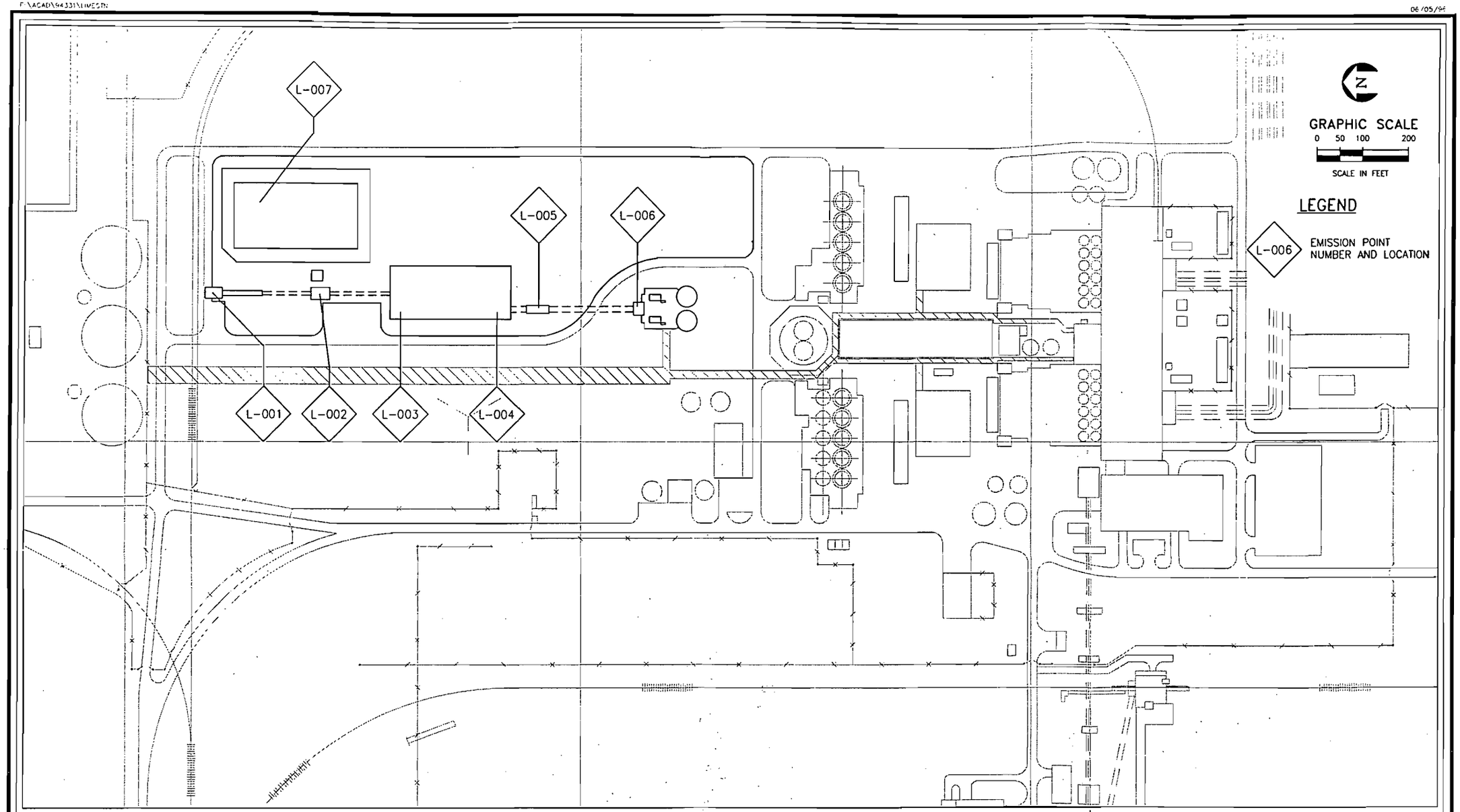

FIGURE II.D.2.4.

LIMESTONE HANDLING

Source: ECT, 1994.

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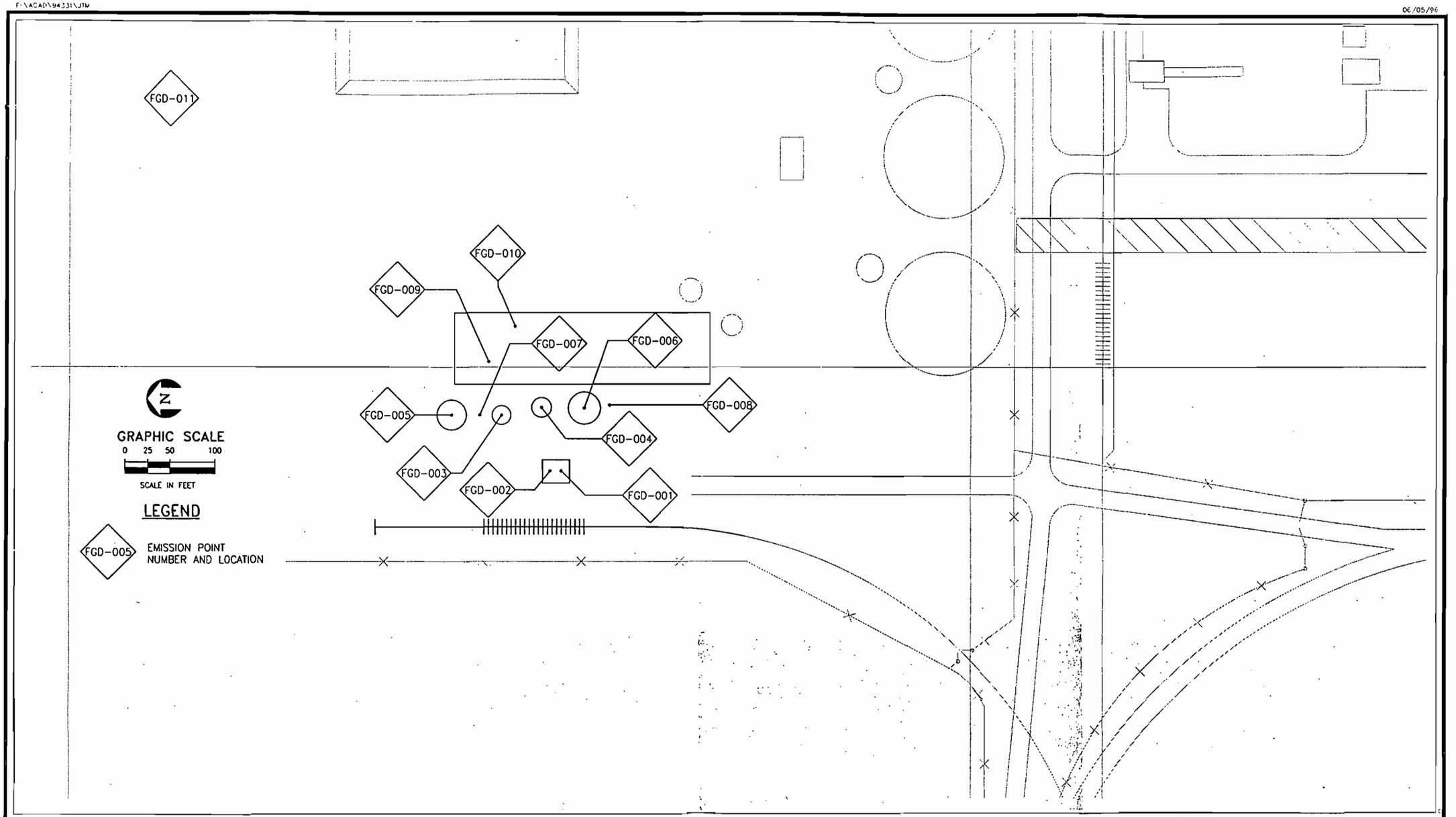

FIGURE II.D.2.5.

FLUE GAS DESULFURIZATION SLUDGE STABILIZATION AREA

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

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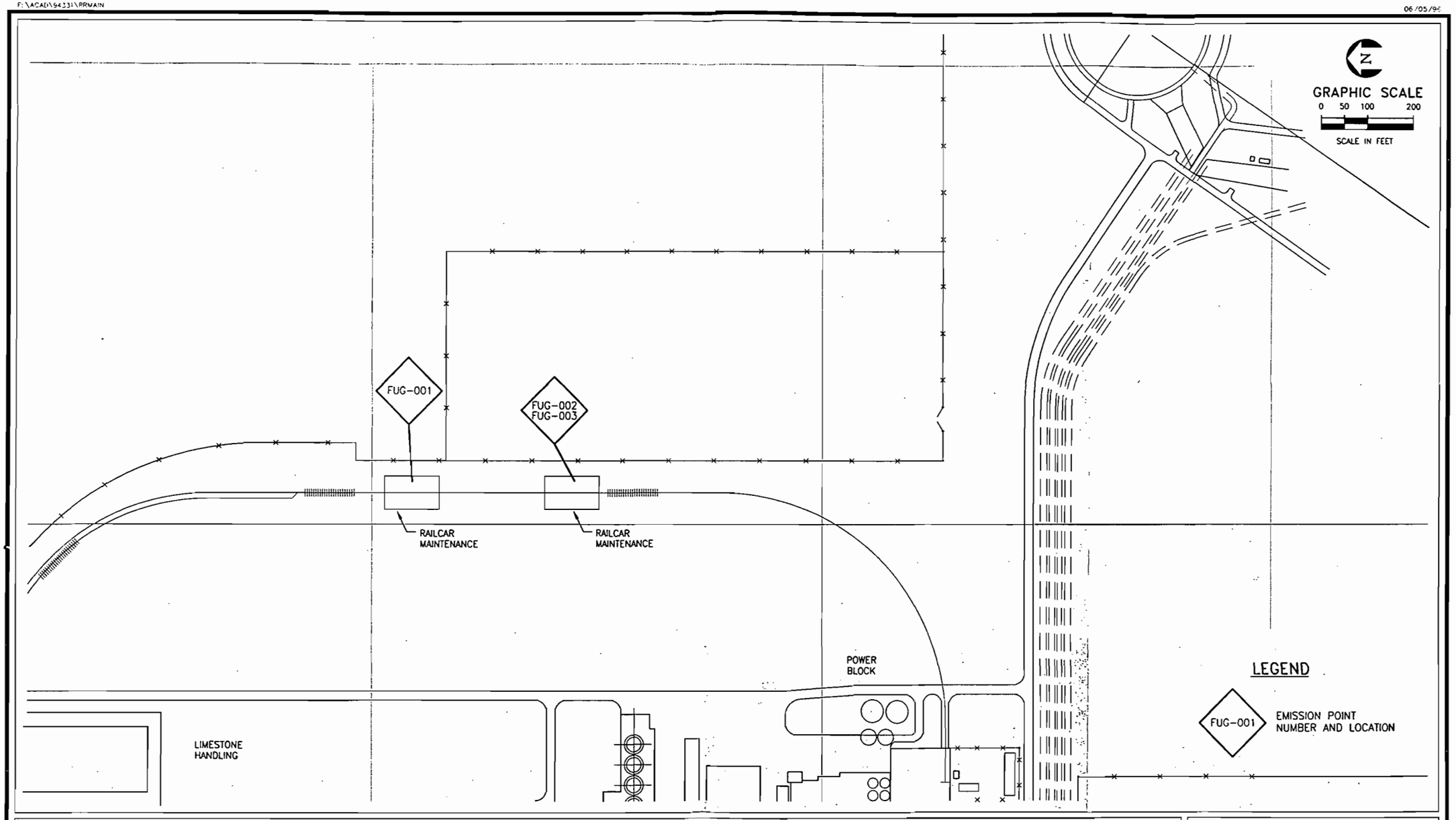


FIGURE II.D.2.6.

RAILCAR MAINTENANCE

Source: ECT, 1996.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

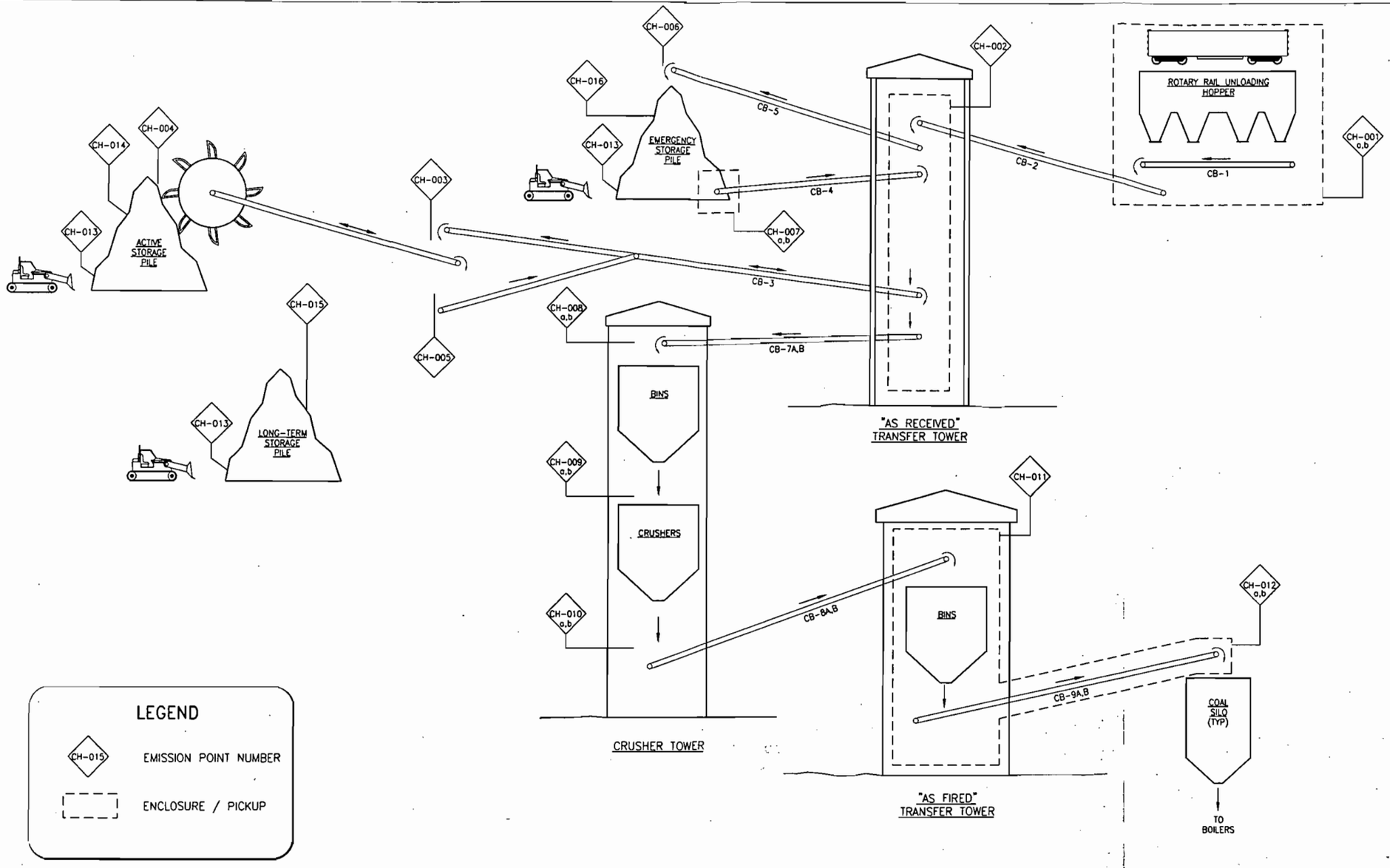


FIGURE II.D.3.2.

PROCESS FLOW SCHEMATIC: COAL HANDLING AND STORAGE

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

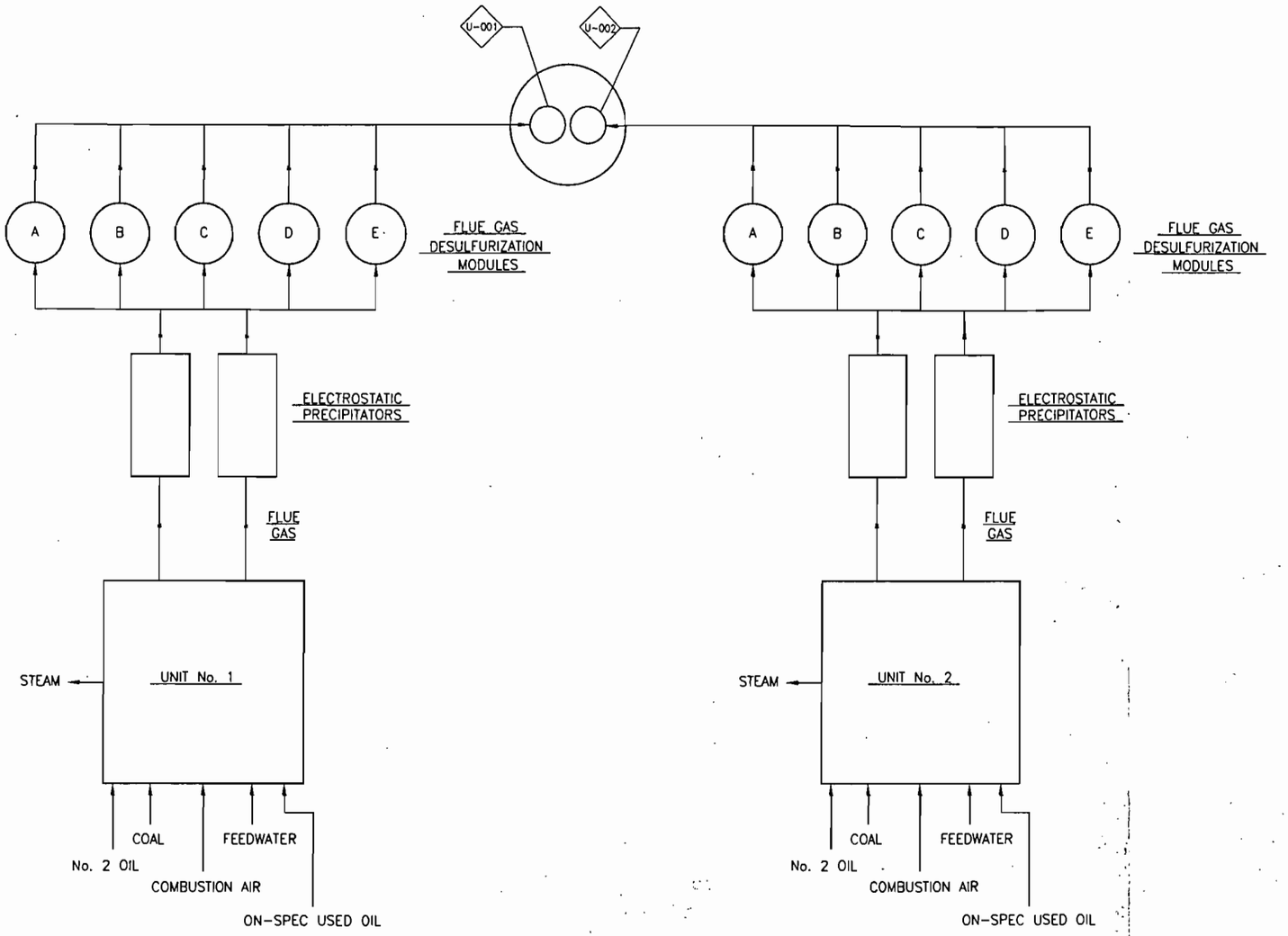


FIGURE II.D.3.3.

BOILER PROCESS FLOW DIAGRAM

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

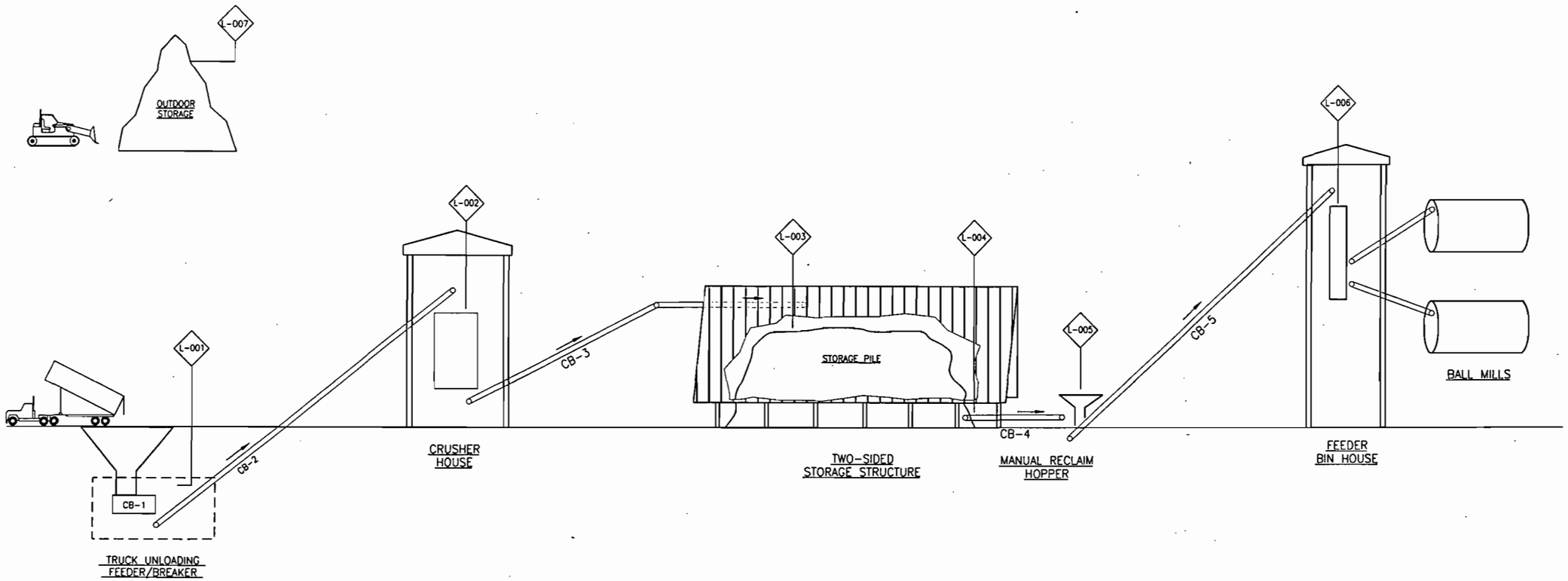


FIGURE II.D.3.4.

LIMESTONE HANDLING PROCESS FLOW DIAGRAM

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

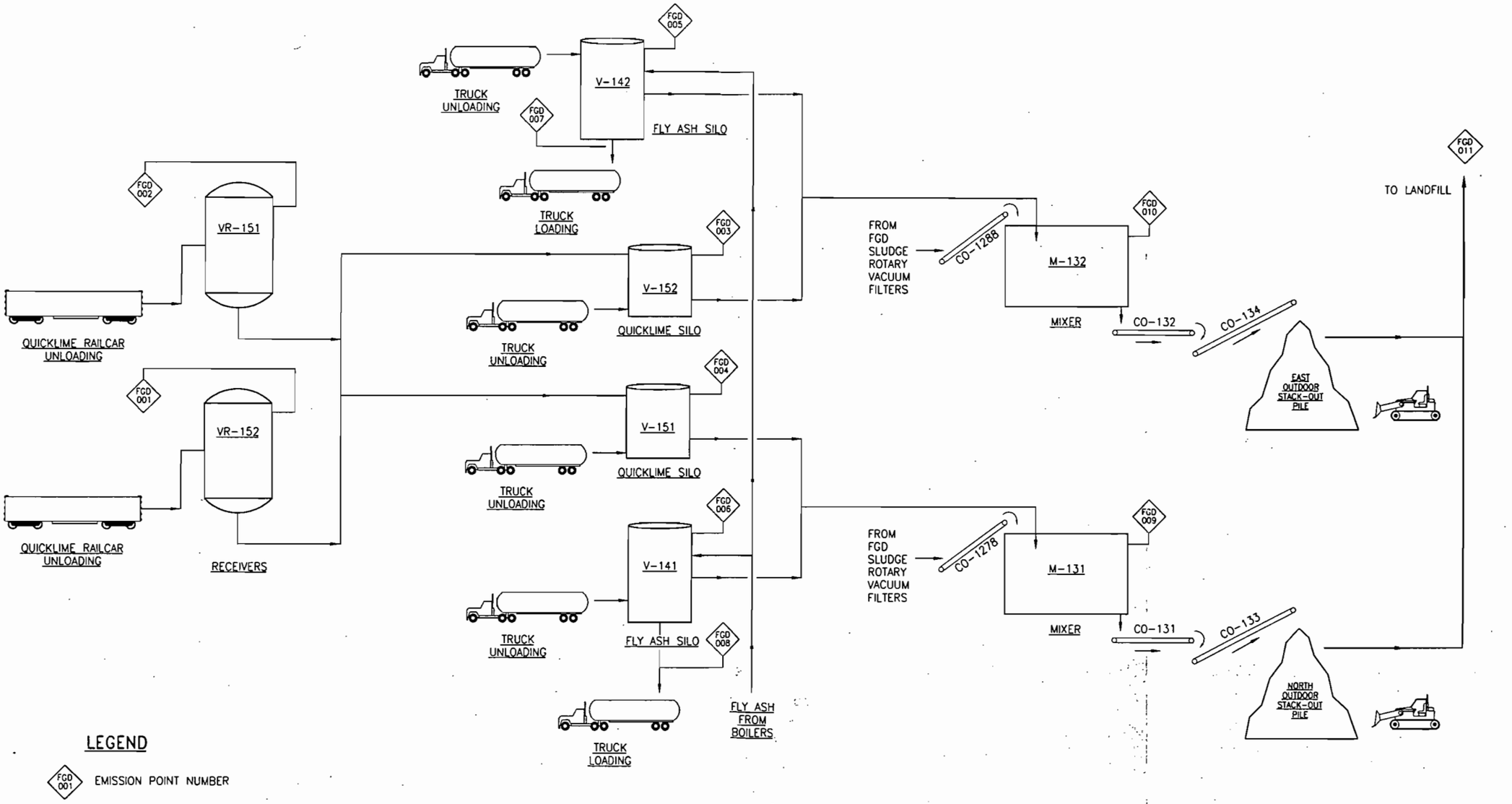
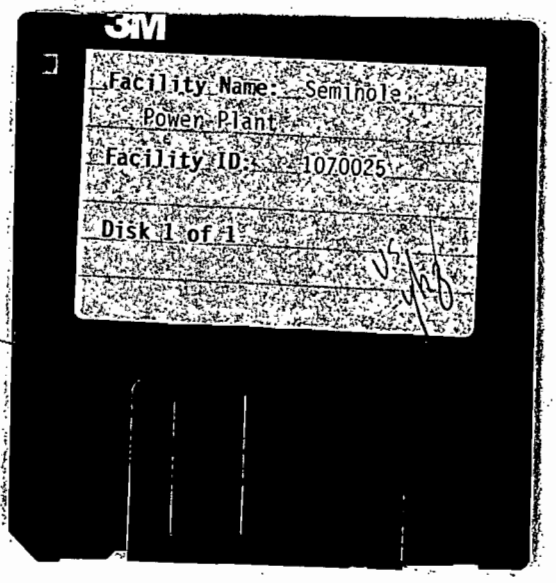


FIGURE II.D.3.5.

FGD SLUDGE STABILIZATION PROCESS FLOW DIAGRAM

Source: ECT, 1994.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED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Facility Name: Seminole
Power Plant
Facility ID: 1070025
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