ORLANDO UTILITIES COMMISSION

Indian River Plant

Title V Operating Permit Application
June 15, 1996

Control No. 1

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

RECEIVED
JUN 17 1996
BUREAU OF
AIR REGULATION

Identification of Facility Addressed in This Application

Indian River Plant
Orlando Utilities Commission
US 1 & Kings HWY
Titusville, Florida 32780

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official :

Name : Gregory A. DeMuth
Title : Director, Environmental Division

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

Organization/Firm : Orlando Utilities Commission
Street Address : 500 Orange Ave.
City : Orlando
State : FL Zip Code : 32801-

3. Owner/Authorized Representative or Responsible Official Telephone Numbers :

Telephone : (407)423-9141 Fax : (407)236-9616

4. Owner/Authorized Representative or Responsible Official Statement :

I, the undersigned, am the owner or authorized representative of the facility (non-Title V source) addressed in this Application for Air Permit or the responsible official, as defined in Chapter 62-213, 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. Further, I agree to operate and maintain the air pollutant emissions units and air pollution control equipment described in this application 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. If the purpose of this application is to obtain an air operation permit or operation permit revision for one or more emissions units which have undergone construction or modification, I 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 applicatio for air construction permit and with all provisions contained in such permit. 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.*

Signature Gregory A. DeMuth Date 6/14/96

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit
001	Boiler 1
002	Boiler 2
003	Boiler 3
004	Combustion Turbine A
005	Combustion Turbine B
006	Combustion Turbine C
007	Combustion Turbine D

Scope of Application

Emissions Unit ID	Description of Emissions Unit
08	Lime Storage Silo
No Id	Non-regulated Emissions - Exempt and Insignifcant
No Id	Non-regulated Emissions - Significant

Purpose of Application and Category

Category I : All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain :

[X] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number :

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a Title V source to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number :

Operation permit to be revised :

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application.

Operation permit to be revised/corrected :

[ ] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit.

Operation permit to be revised :

Reason for revision :

Category II : All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s) :

[ ] Renewal air operation permit under Fule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a synthetic non-Title V source.

Operation permit to be revised :

Reason for revision :

Category III : All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain :

[ ] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any :

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s) :

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Application Processing Fee

Attached - Amount : NA

Construction/Modification Information

1. Description of Proposed Project or Alterations :
2. Projected or Actual Date of Commencement of Construction :
3. Projected Date of Completion of Construction :

Professional Engineer Certification

1. Professional Engineer Name : G. Preston Lewis, P.E.

   Registration Number : 41755

2. Professional Engineer Mailing Address :

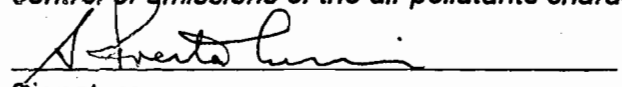
   Organization/Firm : ENSR
   Street Address : P.O. Box 13206
   City : Tallahassee
   State : FL Zip Code : 32317-3206

3. Professional Engineer Telephone Numbers :

   Telephone : (904)385-0808 Fax : (904)385-5457

4. Professional Engineer Statement :

I, the undersigned, hereby certified, except as particularly noted herein, that :*
(1) To the best of my knowledge, there is reasonable assurance (a) that the air pollutant emissions unit(s) and the air pollutant 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 in the Florida Statues and rules of the Department of Environmental Protection; or (b) for any application for a TitleV source air operation permit, that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in the application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application;
(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; and
(3) For any application for an air construction permit for one or more proposed new or modified emissions units, 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.



Signature

6/11/96

Date

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact :

Name : Robert F. Hicks
Title : Senior Environmental Engineer

2. Application Contact Mailing Address :

Organization/Firm : Orlando Utilities Commission
Street Address : 500 South Orange Avenue
City : Orlando
State : FL Zip Code : 32802-3193

3. Application Contact Telephone Numbers :

Telephone : (407)423-9100 Fax : (407)236-9616

Application Comment

Alternate Contacts for the Application:

Preston Lewis, P.E. (904) 385-0808
Barry Andrews, P.E. (205) 767-1210

INDIAN RIVER PLANT FACILITY

ITEM ID	DESCRIPTION	WHERE REFERENCED
Figure 1	Area Map	Facility Supplemental
Figure 2	Facility Plot Plan	Facility Supplemental
Figure 3	Unit 1 Flow Diagram	Facility/E.U. Sup.
Figure 4	Unit 2 Flow Diagram	Facility/E.U. Sup.
Figure 5	Unit 3 Flow Diagram	Facility/E.U. Sup.
Figure 6	Combustion Turbine A	Facility/E.U. Sup.
Figure 7	Combustion Turbine B	Facility/E.U. Sup.
Figure 8	Combustion Turbine C	Facility/E.U. Sup.
Figure 9	Combustion Turbine D	Facility/E.U. Sup.
Figure 10	Lime Storage Silo	Facility/E.U. Sup.
Appendix A	Fugitive Emissions Ident.	Facility Supplemental
Appendix B	Insignificant Activities	Facility Supplemental
Appendix C	Alternative Methods	Facility Supplemental
Appendix D	Compliance Plan & Report	Facility Supplemental
Appendix E	Compliance Statement	Facility Supplemental
Appendix F	Fuel Analysis	E.U. Supplemental
Appendix G	Compliance Report(s)	E.U. Supplemental
Appendix H	O&M Plan/ Startup/Shutdown	E.U. Supplemental
Appendix I	Acid Rain Application(s)	E.U. Supplemental
Appendix J	Control Equipment (s)	E.U. Supplemental
Appendix K	Additional Rules	Facility/E.U. Sup.
Appendix L	ENSR MathCad/Emissions Inventory/Calcs.	Facility/E.U. Sup.
Appendix M	Title VI Information	Facility/E.U. Sup.

FIGURE 1

AREA MAP

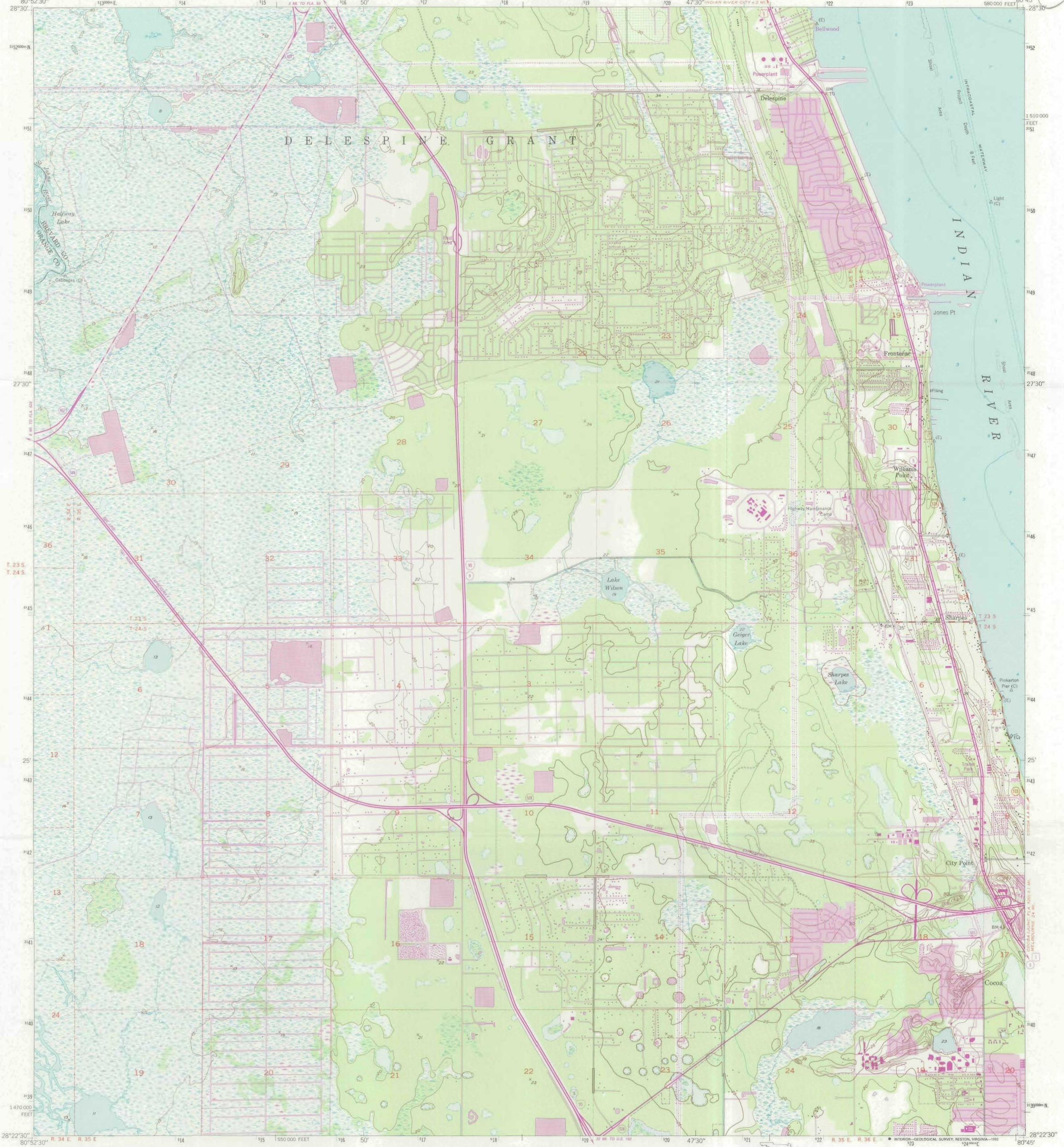
UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

UNITED STATES
DEPARTMENT OF COMMERCE
COAST AND GEODETIC SURVEY

0090008-001

SHARPES QUADRANGLE
FLORIDA
7.5 MINUTE SERIES (TOPOGRAPHIC)

(1)



Mapped by the U. S. Coast & Geodetic Survey
Edited and Published by the Geological Survey

Control by USGS, NOS/NOAA and USCE

Culture and drainage in part compiled from aerial photographs taken 1948
Topography by planetable surveys 1948. Field checked 1949
Hydrography from charts surveyed 1876 to 1941

Projection and 10,000-foot grid ticks: Florida coordinate system, east zone (transverse Mercator)
1000-meter Universal Transverse Mercator grid ticks, zone 17, shown in blue
1927 North American Datum (NAD 27)

North American Datum of 1983 (NAD 83) is shown by dashed corner ticks
The values of the shift between NAD 27 and NAD 83 for 7.5-minute intersections are given in USGS Bulletin 1875

Dashed land lines indicate approximate locations
Land lines within Delespine Grant omitted due to insufficient information

Photoinspected from 1989 source; no major culture or drainage changes observed. Boundaries revised and names verified 1992

MN GN
4° 71 MILS
0°05' 1 MIL
UTM GRID AND 1992 MAGNETIC NORTH DECLINATION AT CENTER OF SHEET

SCALE 1:24 000
1 0 1 MILE
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET
1 0 1 KILOMETER

CONTOUR INTERVAL 5 FEET
NATIONAL GEODETIC VERTICAL DATUM OF 1929
DEPTH CURVES AND SOUNDINGS IN FEET—DATUM IS MEAN LOW WATER
THE RELATIONSHIP BETWEEN THE TWO DATUMS IS VARIABLE
SHORELINE SHOWN REPRESENTS THE APPROXIMATE LINE OF MEAN HIGH WATER
NO APPRECIABLE PERIODIC TIDES IN THIS AREA

THIS MAP COMPLIES WITH NATIONAL MAP ACCURACY STANDARDS
FOR SALE BY U. S. GEOLOGICAL SURVEY
DENVER, COLORADO 80225, OR RESTON, VIRGINIA 22092
A FOLDER DESCRIBING TOPOGRAPHIC MAPS AND SYMBOLS IS AVAILABLE ON REQUEST

FLORIDA
QUADRANGLE LOCATION

1	2	3
4		5
6	7	8

1 Titusville SW
2 Titusville
3 Orsino
4 Lake Poinsett NW
5 Courtenay
6 Lake Poinsett SW
7 Lake Poinsett
8 Cocoa

ADJOINING 7.5' QUADRANGLE NAMES

Revisions shown in purple compiled from aerial photographs taken 1984 and other sources. This information not field checked. Map edited 1988

Purple tint indicates extension of urban areas

ROAD CLASSIFICATION
Heavy-duty
Medium-duty
Light-duty
Unimproved dirt
Interstate Route
U. S. Route
State Route

SHARPES, FLA.
28080-D7-TF-024

1949
PHOTOREVISED 1988
MINOR REVISION 1992

INTERIOR—GEOLOGICAL SURVEY, RESTON, VIRGINIA—1992

FIGURE 2

FACILITY PLOT PLAN

LEGEND

- NEW ASPHALTIC SURFACING
- EXISTING ASPHALTIC SURFACING
- NEW CONCRETE SURFACING
- EXISTING CONCRETE SURFACING
- COQUINA OR LOCAL SHELL BASE SURFACE
- NEW CRUSHED ROCK SURFACING
- EXISTING CRUSHED ROCK SURFACING
- EXISTING FABRIC FORM
- NEW FENCING
- EXISTING FENCING
- NEW CONTOURS
- EXISTING CONTOURS
- × EL 122.50 NEW SPOT ELEVATIONS
- △ EXISTING HORIZONTAL & VERTICAL CONTROL MONUMENT

HVCM	PLANT COORDINATE N–S	PLANT COORDINATE E–W	ELEVATION
1	S 5+14.50	E 3+10.00	23.390
2	N 1+40.50	E 3+10.00	24.741
3	N 1+40.50	W 3+40.00	25.613

NOTES

1. ALL WORK INDICATED ON DRAWINGS S3001 AND S3002 SHALL BE CONSTRUCTED BY CONTRACT 71.0402 UNLESS NOTED OTHERWISE.
2. THE CONTRACTOR SHALL TAKE PRECAUTIONS TO AVOID DAMAGING THE EXISTING TEST WELLS DURING THE COURSE OF HIS WORK.
3. PLANT DATUM IS BASED ON ELEVATION 100 BEING MEAN SEA LEVEL AND EQUAL TO UNITED STATES COAST AND GEODETIC SURVEY DATUM 00.00.
4. ELEVATIONS INDICATED ON EXISTING CONTROL MONUMENTS ARE USGS ELEVATIONS.
5. THE CURB CONTAINING THE CRUSHED ROCK SHALL FOLLOW THE EDGE OF PAVEMENT AS INDICATED.

EXST FUEL OIL STORAGE TANK NO. 3
EXST FUEL OIL STORAGE TANK NO. 2
EXST FUEL OIL STORAGE TANK NO. 1
EXST DEMINERALIZED WATER STORAGE TANK
EXST RAW WATER TANK
EXST TREATED WATER TANK
EXST DION WATER TANK
EXST LT. OIL STORAGE TANK 1
NEW NEUTRALIZATION BASIN
NEW WATER TREATMENT BUILDING ADDITION
EXST CONDENSATE STORAGE TANK
EXST WATER TREATMENT BUILDING
EXST GATE HOUSE
EXST FUEL PUMP FOUNDATION
EXST UNIT NO. 3 STACK
EXST UNIT NO. 1 & 2 STACK
EXST OFFICES
EXST WAREHOUSE
EXST LIGHT OIL STORAGE TANK 2
EXST PERCOLATION PONDS
NEW FUEL OIL UNLOADING STATION
EXST TEST WELL
HVCM-1
HVCM-2
HVCM-3
EXST VALVE STATION AREA
CL EXST ROAD N 0+90
EXST POWER PLANT BUILDING
UNIT NO. 3
UNIT NO. 2
UNIT NO. 1
EXST MAINTENANCE BUILDING
EXST SUBSTATION CONTROL BLDG
EXST SUBSTATION
ALL FENCING WORK IN SUBSTATION EXPANSION BY CONTRACT EL-30A
TYPE II FILL BY CONTRACT 71.0402
EXST GUARD STATION
EXST WAREHOUSE
EXST RAILROAD SPUR
CL TRENCH 9 W 1+55 INV EL 122.70
CL TRENCH 10 S 4+23 INV EL 121.80
CL ROAD W 2+20
CL ROAD W 0+66
CL ROAD S 4+07
CL ROAD S 4+50
CL ROAD E 0+99
CL RELOCATED 18" CATE E 0+99
INV EL 122.50
INV EL 121.60
INV EL 120.5
EXST 24"ø CULVERT
EXST CULVERT
NOTE: CONTRACTOR SHALL CLEAN OUT EXISTING CULVERTS
SEE NOTE 5
KINGS HIGHWAY
BASELINE 0+00

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP	FLM
4	02-19-93	CONFORMED TO CONSTRUCTION RECORDS	VFD	LJS		
3	02-14-92	ECN-003	RLW	VFD	LJS	
2	10-11-91	RELEASED FOR CONSTRUCTION	RDB	RLW	VFD	
1	07-01-91	REVISED ROADWAY	RLW		VFD	
0	06-14-91	INITIAL ISSUE	RDB		VFD	

50' 25' 0 50' 100'
1"=50'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA
SIGNED V. F. DANNER
DATE 06-14-91 REG NO. 32245

BLACK & VEATCH

ORLANDO UTILITIES COMMISSION
INDIAN RIVER PLANT-C.T. UNITS C & D

SITE - GRADING AND SURFACING PLAN

ENGINEER	RDB	DRAWN	EGS
CHECKED	RLW	DATE	10-9-91

PROJECT 17135-9STU-S3001
DRAWING NUMBER
REV 4
CODE
AREA

11285WENSON ACAD 10 c10a 0090008-001
1"=50' 06-14-91
01/22/93 06:01:24

(2)

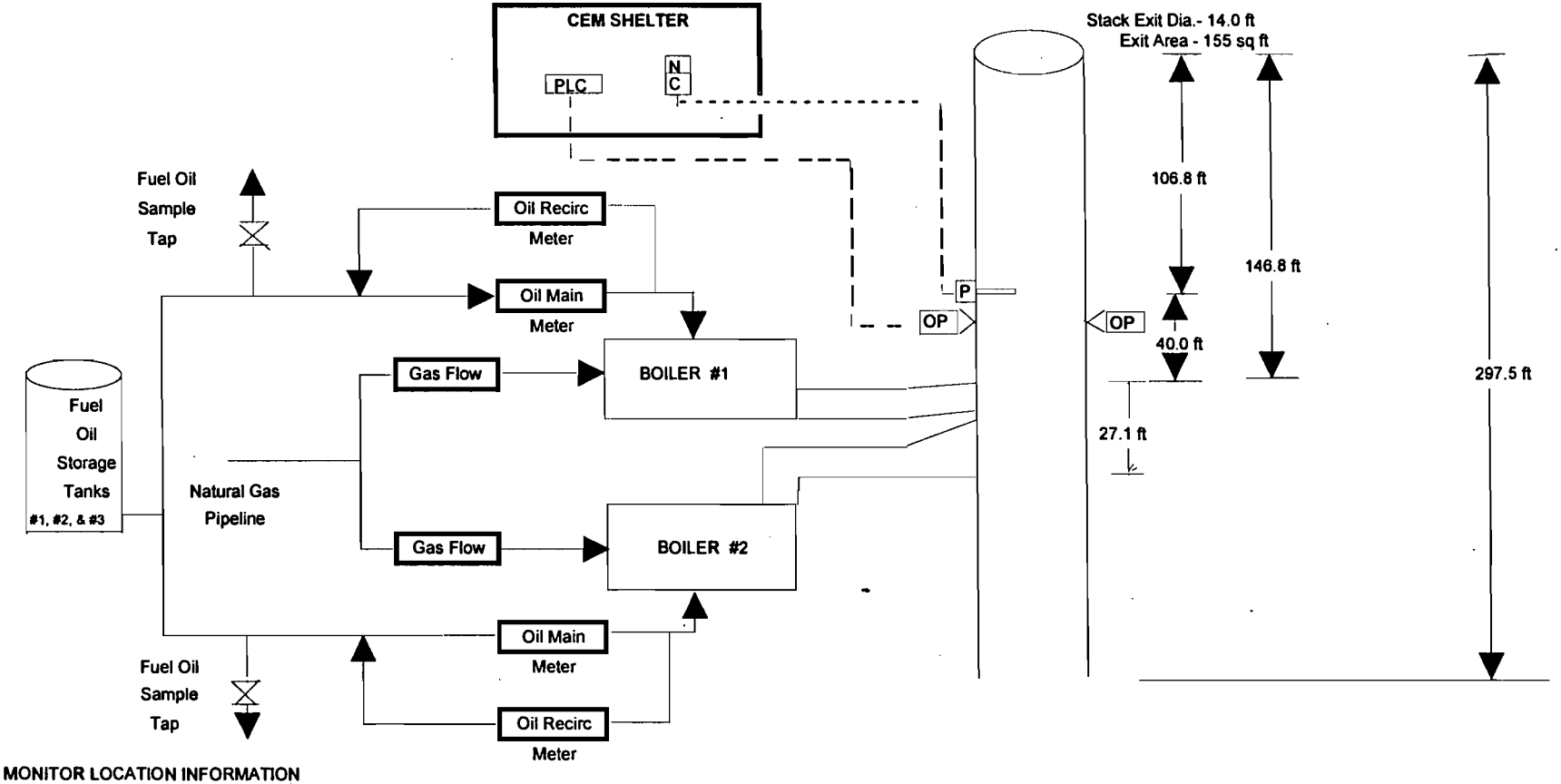
FIGURE 3

UNIT 1 PROCESS

FLOW DIAGRAM

SCHEMATIC of CONTINUOUS MONITORING SYSTEM

INDIAN RIVER PLANT
ORIS Code: 683
NADB Boiler ID: 1 & 2



MONITOR LOCATION INFORMATION

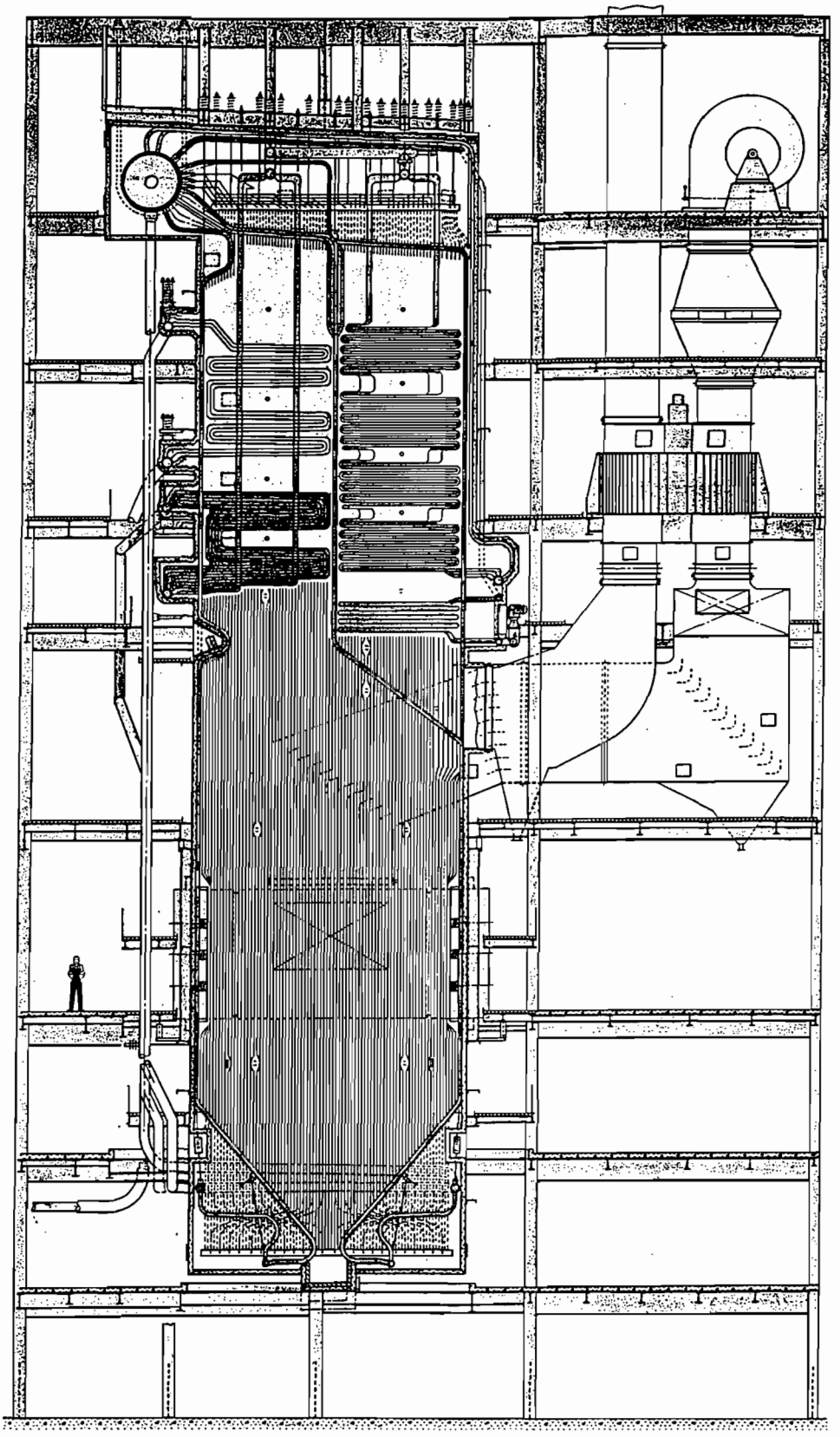
A.	STACK HEIGHT ABOVE GRADE (FT)	297.5
B.	STACK DIAMETER AT TEST PORT (FT)	14.9
C.	INSIDE CROSS-SECTIONAL AREA AT TEST PORT (SQ FT)	174
D.	TEST PORT ELEVATION	
	1 ABOVE GRADE (FT)	190.7
	2 ABOVE LAST DISTURBANCE	
	A. FEET	40.0
	B. STACK DIAMETERS	2.7
	3 PRIOR TO NEXT DISTURBANCE	
	A. FEET	106.8
	B. STACK DIAMETERS	7.2

E. LOCATION OF SAMPLE PROBE. GASEOUS EXTRACTION PROBE IS IN SAME PLANE AS TEST PROBE. OPACITY PROBE IS 1 FT BELOW SAMPLE PROBE ELEVATION.

F. OPACITY MONITOR CROSS SECTIONAL AREA (SQ FT) 175

G. INSIDE CROSS SECTIONAL AREA AT FLUE EXIT (SQ FT) 155

UNIT 1



C-E REHEAT STEAM GENERATOR

CAPACITY – 635,000 LB PER HR AT 1850 PSI AND 1005 F TEMP. – REHEAT 1005 F

Designed and Manufactured by COMBUSTION ENGINEERING, INC.

INDIAN RIVER PLANT – UNIT No. 1

Orlando Utilities Commission, Orlando, Florida

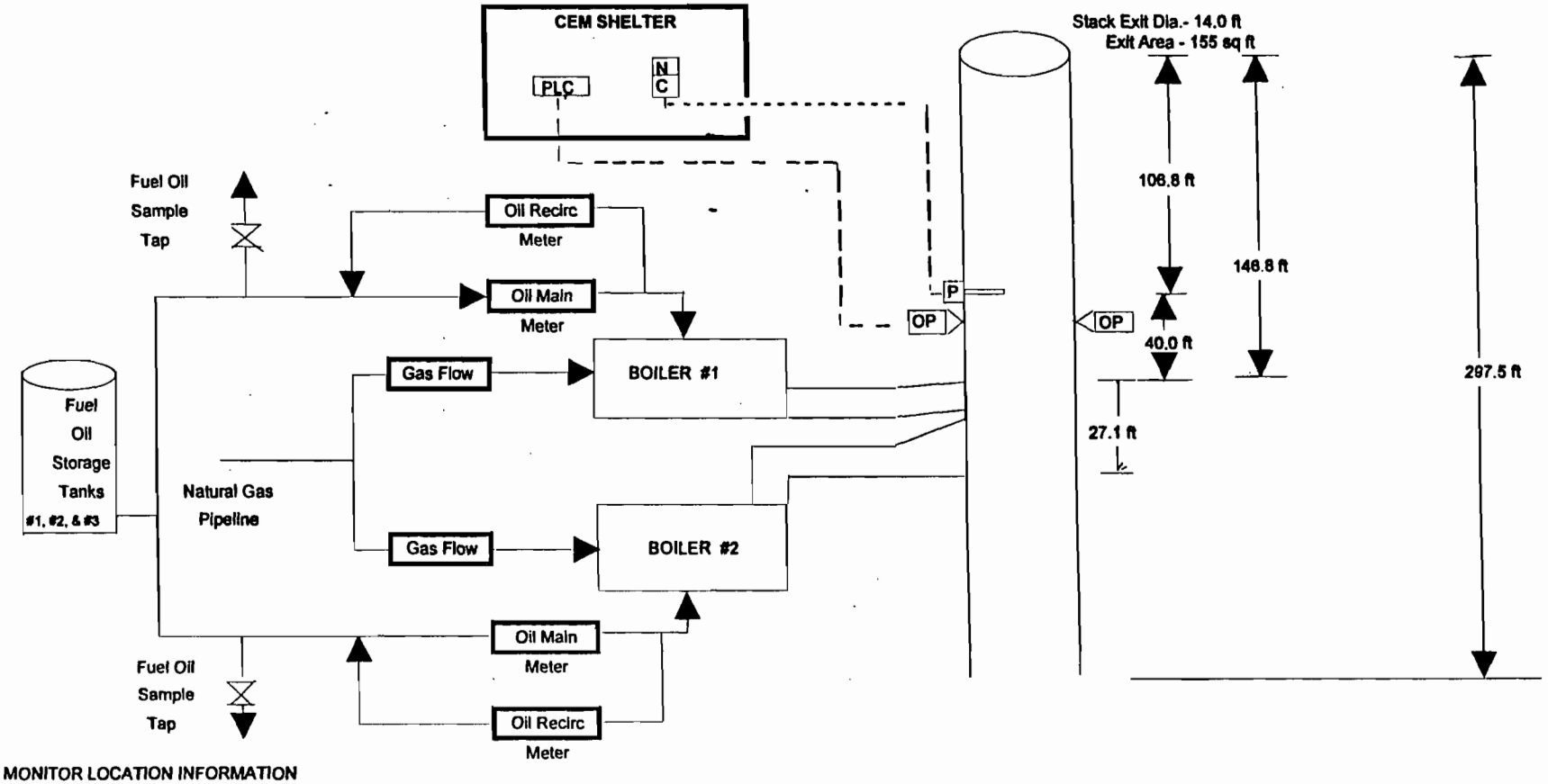
FIGURE 4

UNIT 2 PROCESS

FLOW DIAGRAM

SCHEMATIC of CONTINUOUS MONITORING SYSTEM

INDIAN RIVER PLANT
ORIS Code: 683
NADB Boiler ID: 1 & 2



MONITOR LOCATION INFORMATION

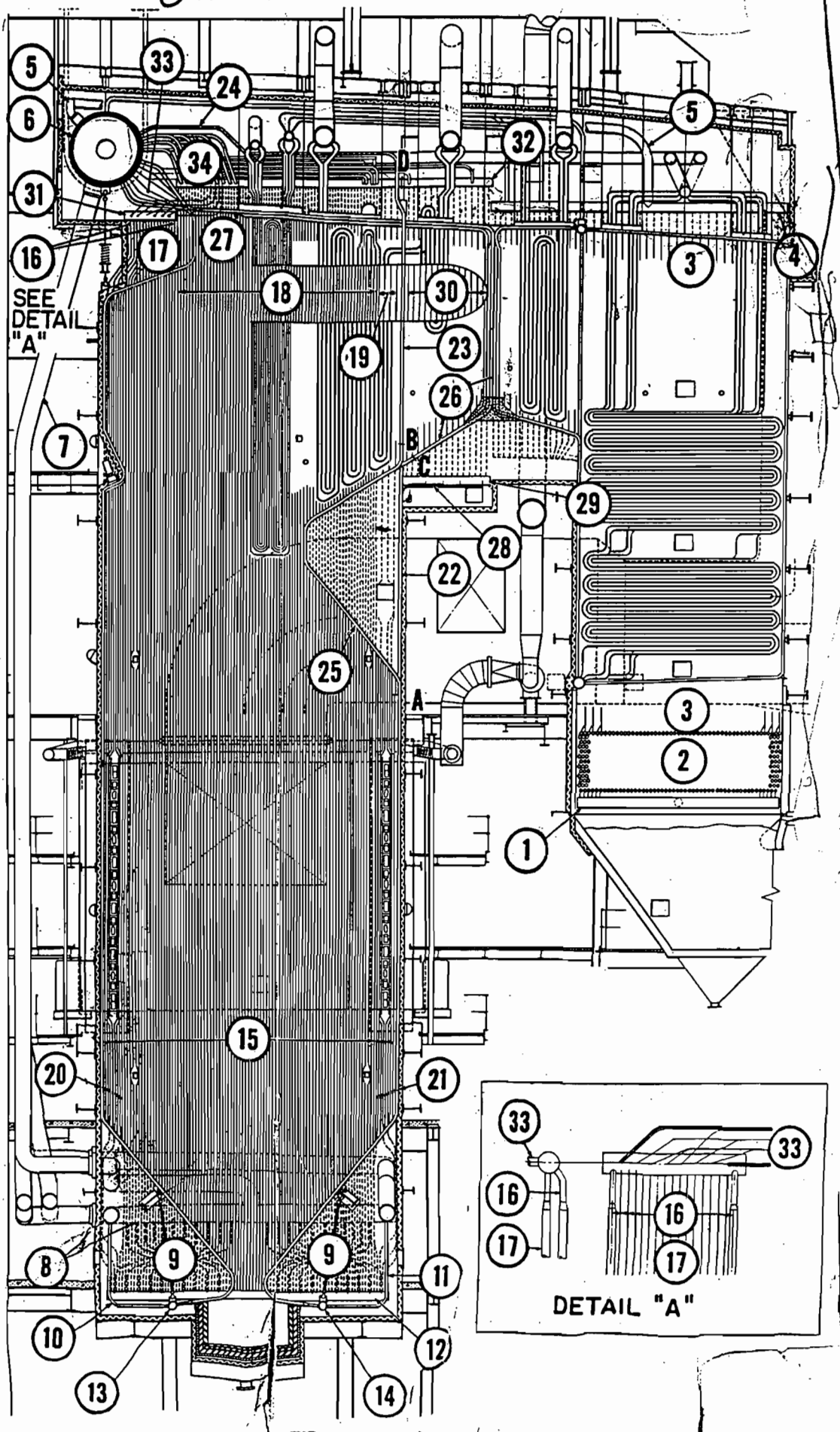
A.	STACK HEIGHT ABOVE GRADE (FT)	297.5
B.	STACK DIAMETER AT TEST PORT (FT)	14.9
C.	INSIDE CROSS-SECTIONAL AREA AT TEST PORT (SQ FT)	174
D.	TEST PORT ELEVATION	
	1 ABOVE GRADE (FT)	190.7
	2 ABOVE LAST DISTURBANCE	
	A. FEET	40.0
	B. STACK DIAMETERS	2.7
	3 PRIOR TO NEXT DISTURBANCE	
	A. FEET	106.8
	B. STACK DIAMETERS	7.2

E. LOCATION OF SAMPLE PROBE. GASEOUS EXTRACTION PROBE IS IN SAME PLANE AS TEST PROBE. OPACITY PROBE IS 1 FT BELOW SAMPLE PROBE ELEVATION.

F. OPACITY MONITOR CROSS SECTIONAL AREA (SQ FT) 175

G. INSIDE CROSS SECTIONAL AREA AT FLUE EXIT (SQ FT) 155

UNIT 2



tubes each corner
headers
corner tubes
et headers

et headers

et headers

2" O.D. at "B"

m Drum

at "D"

GEMENT
M RCUITS

mmissio
it #2
061

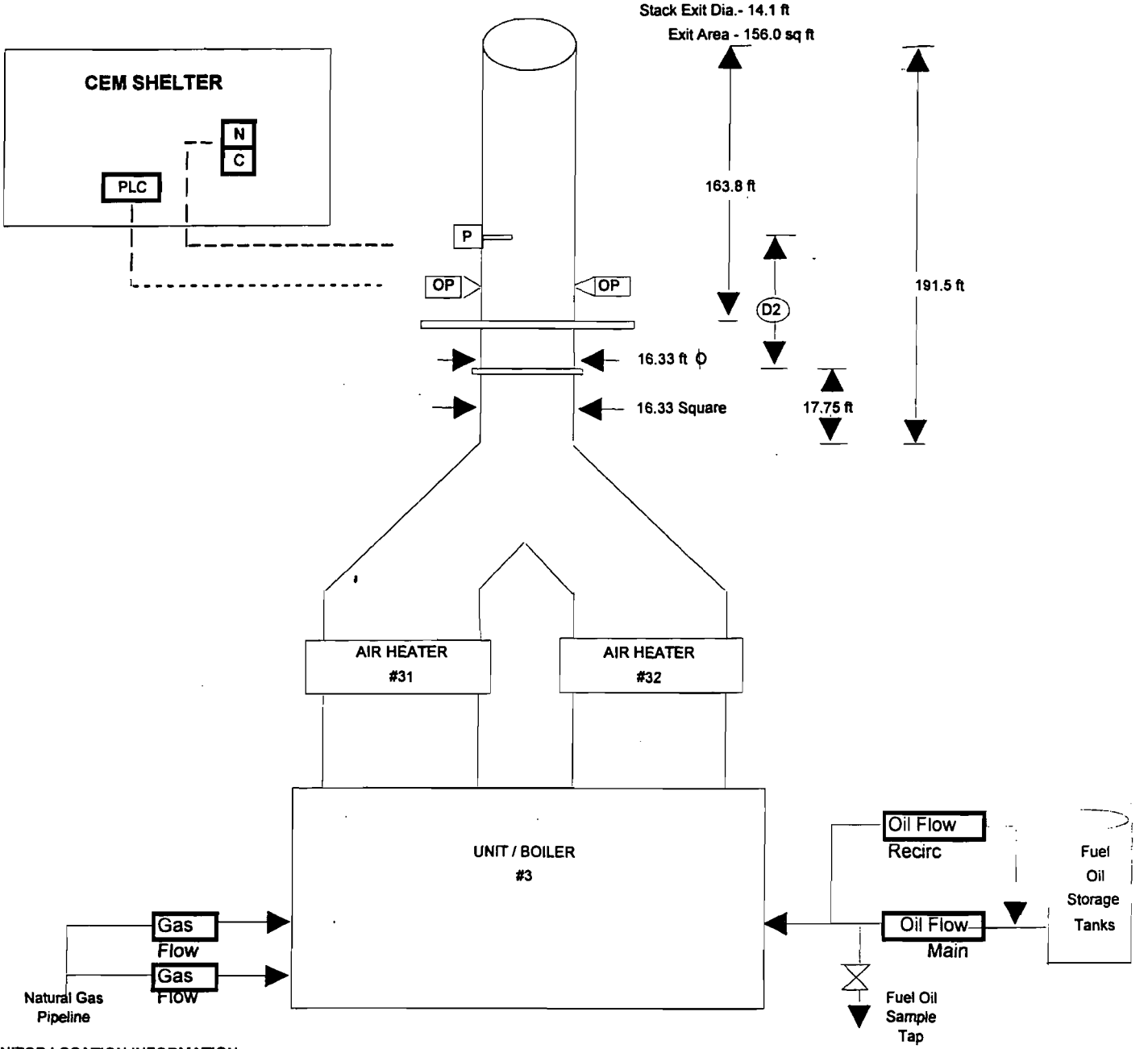
FIGURE 5

UNIT 3 PROCESS

FLOW DIAGRAM

INDIAN RIVER PLANT
ORIS Code: 683
NADB Boiler ID: 3

SCHEMATIC of CONTINUOUS MONITORING SYSTEM



MONITOR LOCATION INFORMATION

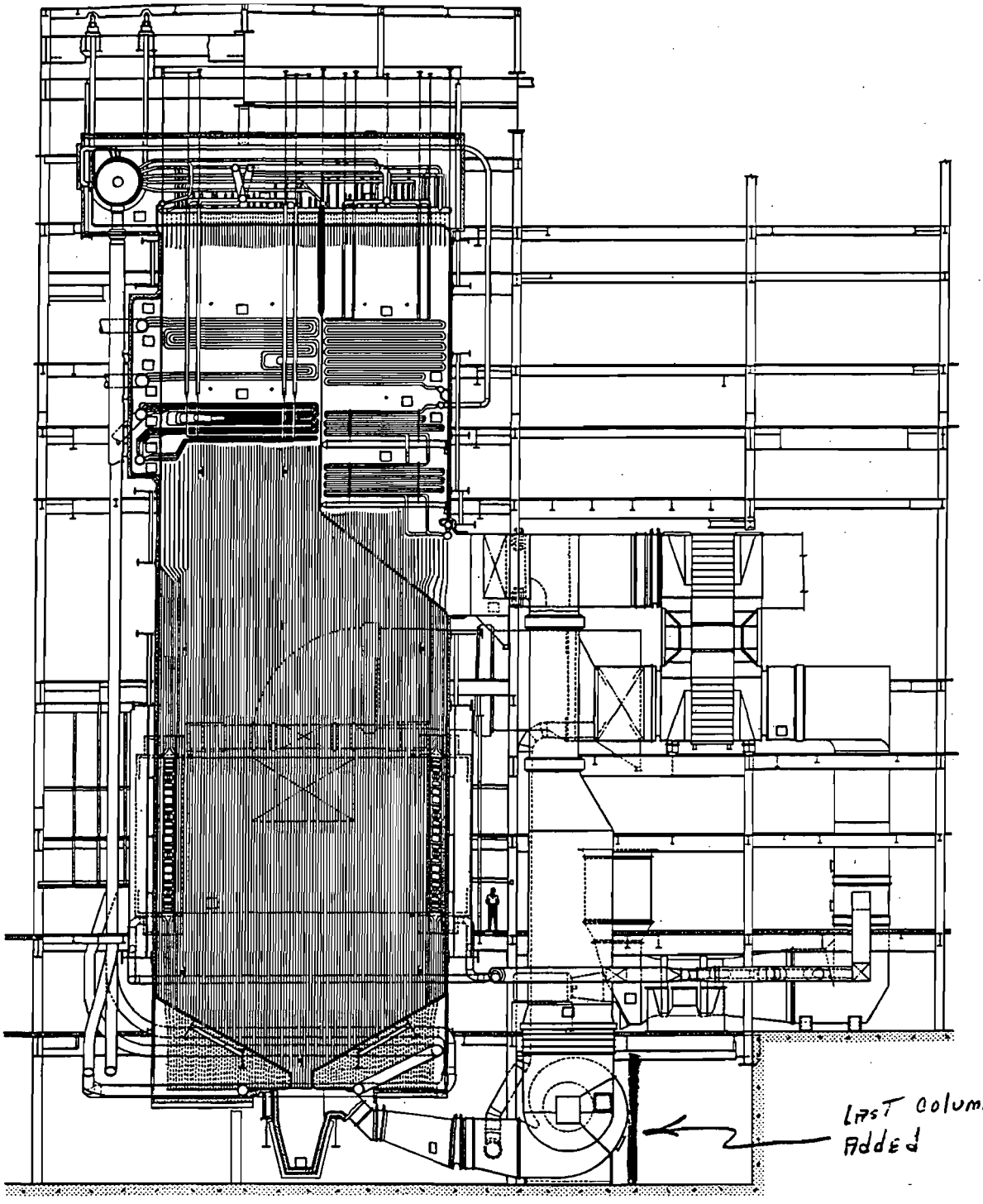
A.	STACK HEIGHT ABOVE GRADE (FT)	297.5
B.	STACK DIAMETER AT TEST PORT (FT)	16.5
C.	INSIDE CROSS-SECTIONAL AREA AT TEST PORT (SQ FT)	215
D.	TEST PORT ELEVATION	
1	ABOVE GRADE (FT)	160
2	ABOVE LAST DISTURBANCE	
A.	FEET	36
B.	STACK DIAMETERS	2.2
3	PRIOR TO NEXT DISTURBANCE	
A.	FEET	137.5
B.	STACK DIAMETERS	8.3

E. LOCATION OF SAMPLE PROBE. GASEOUS EXTRACTION PROBE IS IN SAME PLANE AS TEST PROBE. OPACITY PROBE IS 22 FT BELOW SAMPLE PROBE ELEVATION.

F. OPACITY MONITOR CROSS SECTIONAL AREA (SQ FT) 225

G. INSIDE CROSS SECTIONAL AREA AT FLUE EXIT (SQ FT) 153

UNIT 3



Dwg. No. 30-466

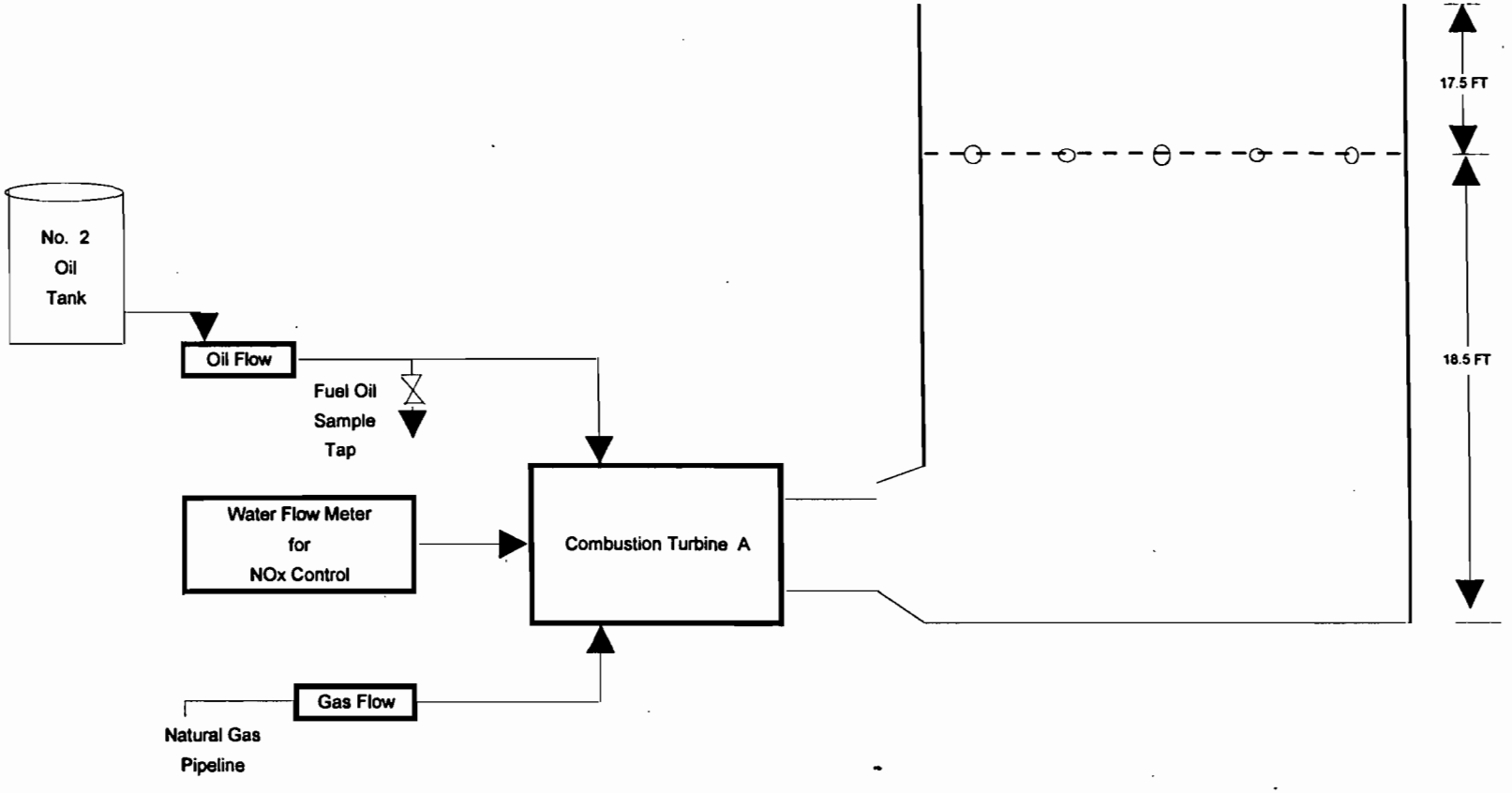
FIGURE 6

COMBUSTION TURBINE A

PROCESS FLOW DIAGRAM

SCHEMATIC of CONTINUOUS MONITORING SYSTEM

INDIAN RIVER PLANT
ORIS Code: 683
NADB Boiler ID: A



MONITOR LOCATION INFORMATION

A.	STACK HEIGHT ABOVE GRADE (FT)	36
B.	STACK DIMENSIONS (FT)	10' X 12'
C.	INSIDE CROSS-SECTIONAL AREA AT TEST PORT (SQ FT)	120
D.	TEST PORT ELEVATION	
1	ABOVE GRADE (FT)	18.5
2	ABOVE LAST DISTURBANCE	
	A. FEET	
	B. STACK DIAMETERS	<.25
3	PRIOR TO NEXT DISTURBANCE	
	A. FEET	
	B. STACK DIAMETERS	<.25
G.	INSIDE CROSS SECTIONAL AREA AT FLUE EXIT (SQ FT)	120

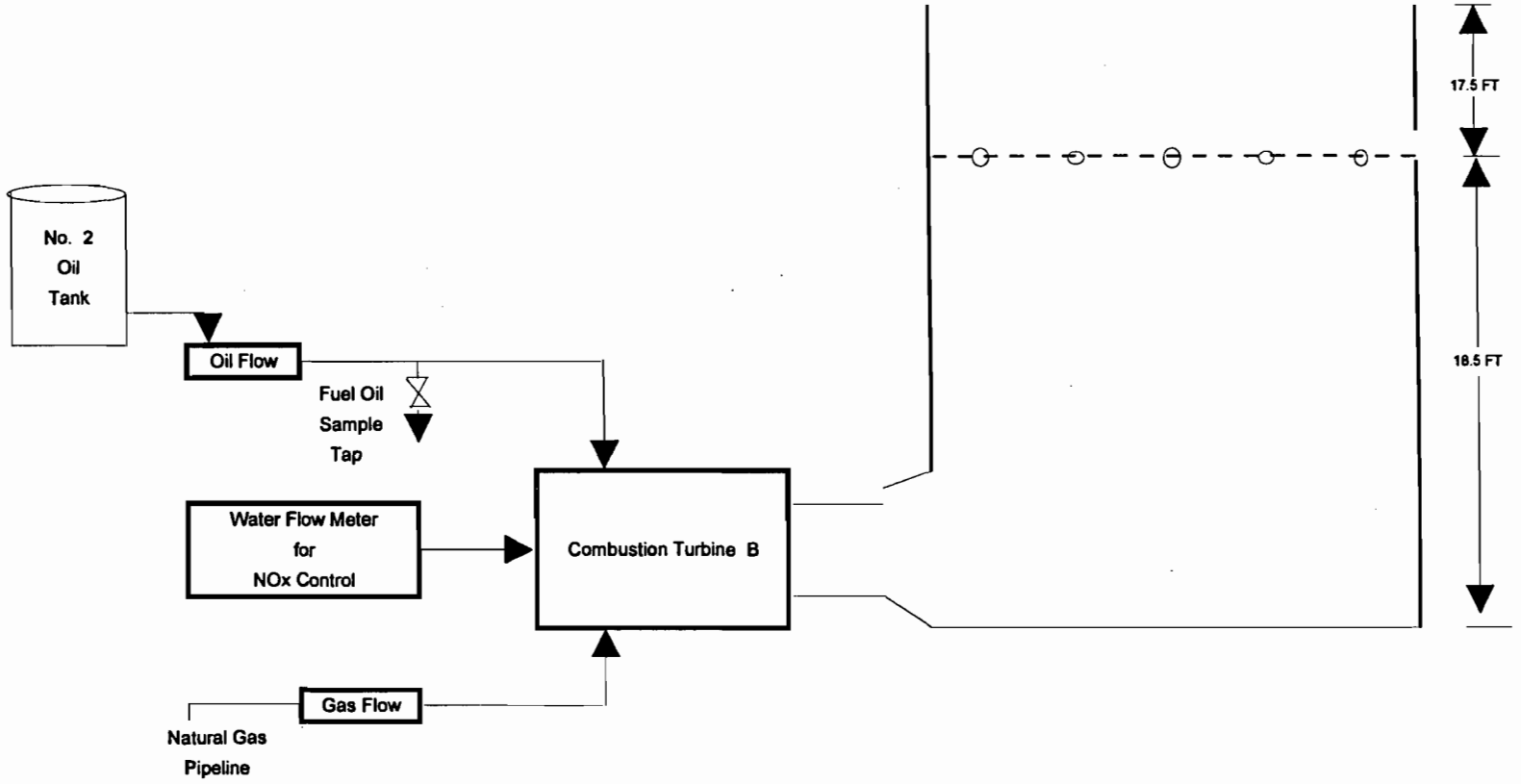
FIGURE 7

COMBUSTION TURBINE B

PROCESS FLOW DIAGRAM

SCHEMATIC of CONTINUOUS MONITORING SYSTEM

INDIAN RIVER PLANT
ORIS Code: 683
NADB Boiler ID: B



MONITOR LOCATION INFORMATION

A.	STACK HEIGHT ABOVE GRADE (FT)	36
B.	STACK DIMENSIONS (FT)	10' X 12'
C.	INSIDE CROSS-SECTIONAL AREA AT TEST PORT (SQ FT)	120
D.	TEST PORT ELEVATION	
1	ABOVE GRADE (FT)	18.5
2	ABOVE LAST DISTURBANCE	
A.	FEET	
B.	STACK DIAMETERS	<.25
3	PRIOR TO NEXT DISTURBANCE	
A.	FEET	
B.	STACK DIAMETERS	<.25
G.	INSIDE CROSS SECTIONAL AREA AT FLUE EXIT (SQ FT)	120

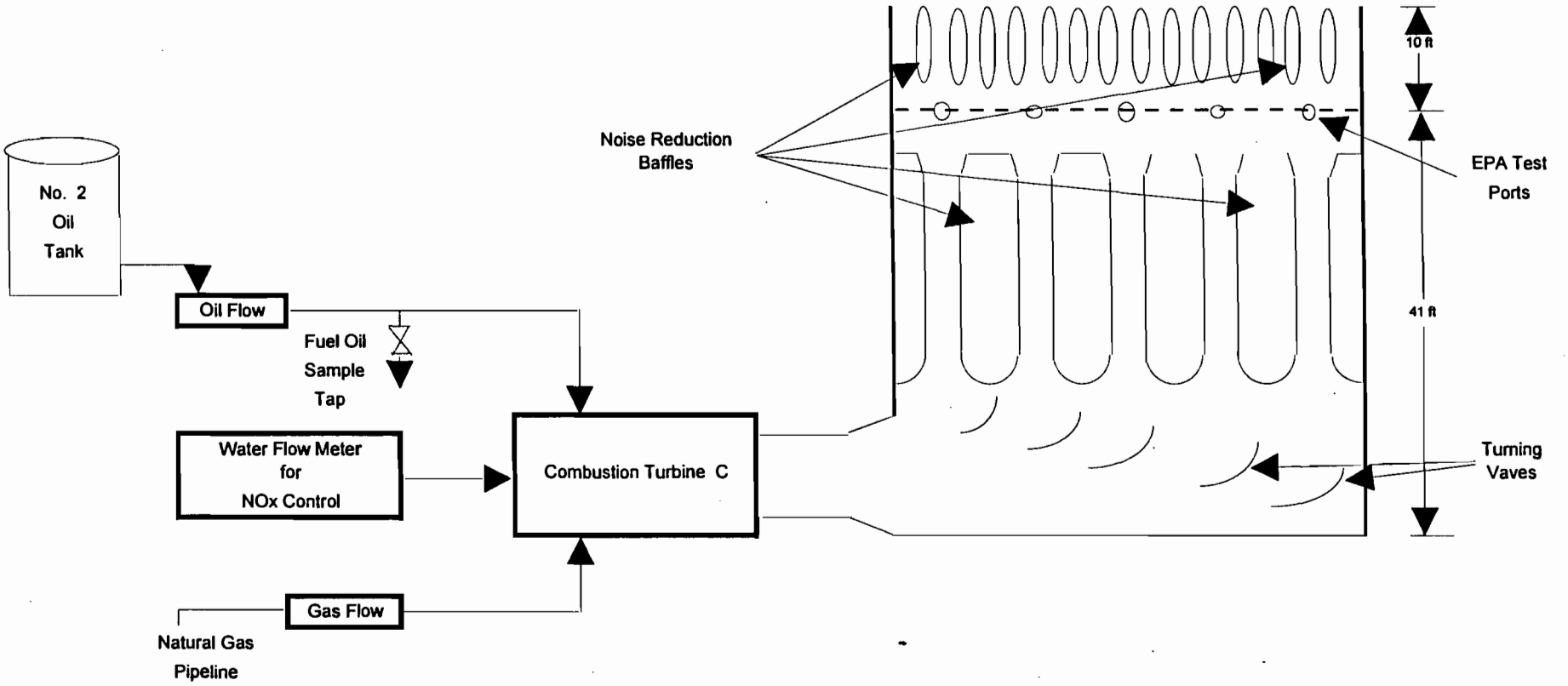
FIGURE 8

COMBUSTION TURBINE C

PROCESS FLOW DIAGRAM

SCHEMATIC of CONTINUOUS MONITORING SYSTEM

INDIAN RIVER PLANT
ORIS Code: 683
NADB Boiler ID: C



MONITOR LOCATION INFORMATION

A.	STACK HEIGHT ABOVE GRADE (FT)	51
B.	STACK DIMENSIONS (FT)	34.3 x 11..2
C.	INSIDE CROSS-SECTIONAL AREA AT TEST PORT (SQ FT)	382.6
D.	TEST PORT ELEVATION	
1	ABOVE GRADE (FT)	41
2	ABOVE LAST DISTURBANCE	
	A. FEET	
	B. STACK DIAMETERS	<.25
3	PRIOR TO NEXT DISTURBANCE	
	A. FEET	
	B. STACK DIAMETERS	<.25
G.	INSIDE CROSS SECTIONAL AREA AT FLUE EXIT (SQ FT)	382.6

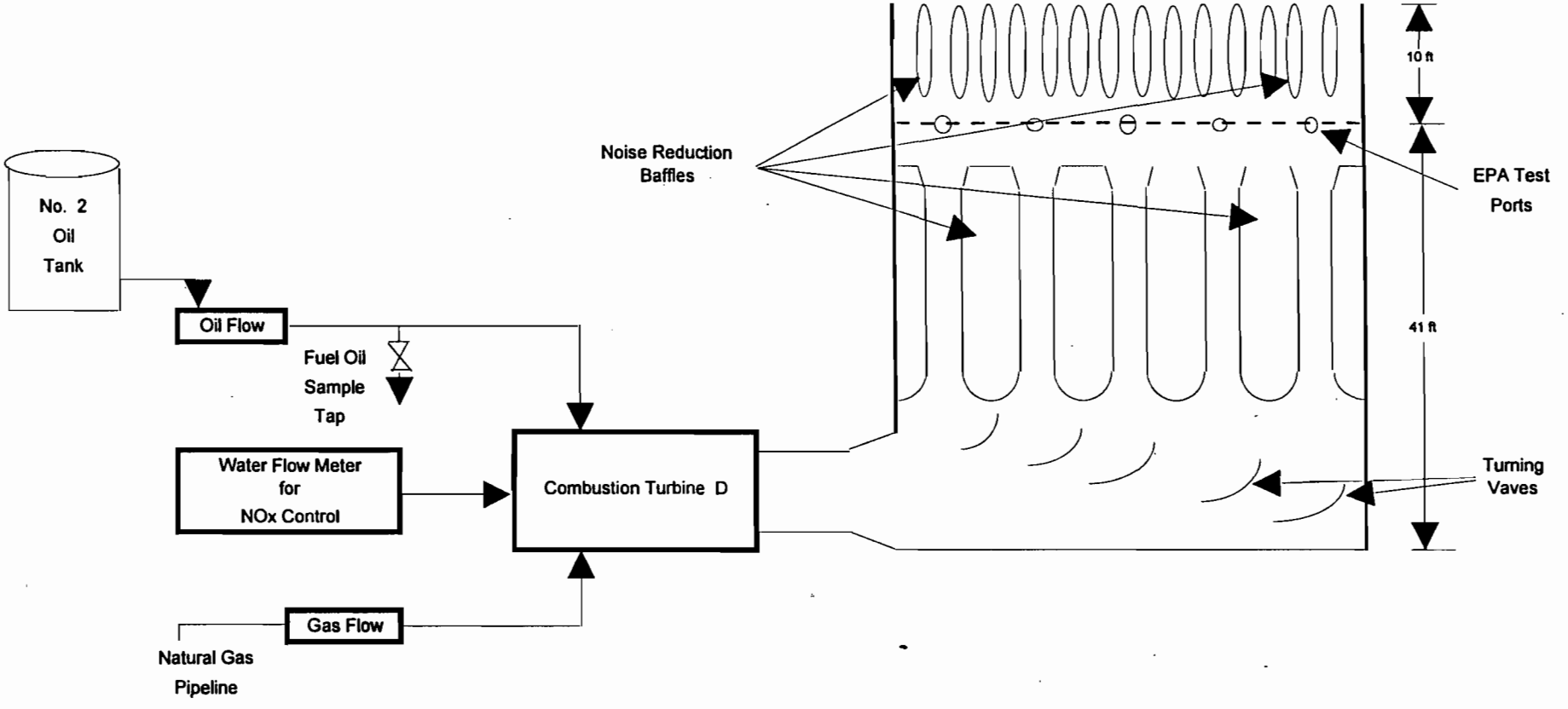
FIGURE 9

COMBUSTION TURBINE D

PROCESS FLOW DIAGRAM

SCHEMATIC of CONTINUOUS MONITORING SYSTEM

INDIAN RIVER PLANT
ORIS Code: 683
NADB Boiler ID: D



MONITOR LOCATION INFORMATION

A.	STACK HEIGHT ABOVE GRADE (FT)	51
B.	STACK DIMENSIONS (FT)	34.3 x 11..2
C.	INSIDE CROSS-SECTIONAL AREA AT TEST PORT (SQ FT)	382.6
D.	TEST PORT ELEVATION	
	1 ABOVE GRADE (FT)	41
	2 ABOVE LAST DISTURBANCE	
	A. FEET	
	B. STACK DIAMETERS	<.25
	3 PRIOR TO NEXT DISTURBANCE	
	A. FEET	
	B. STACK DIAMETERS	<.25
G.	INSIDE CROSS SECTIONAL AREA AT FLUE EXIT (SQ FT)	382.6

FIGURE 10

LIME STORAGE SILO

PROCESS FLOW DIAGRAM

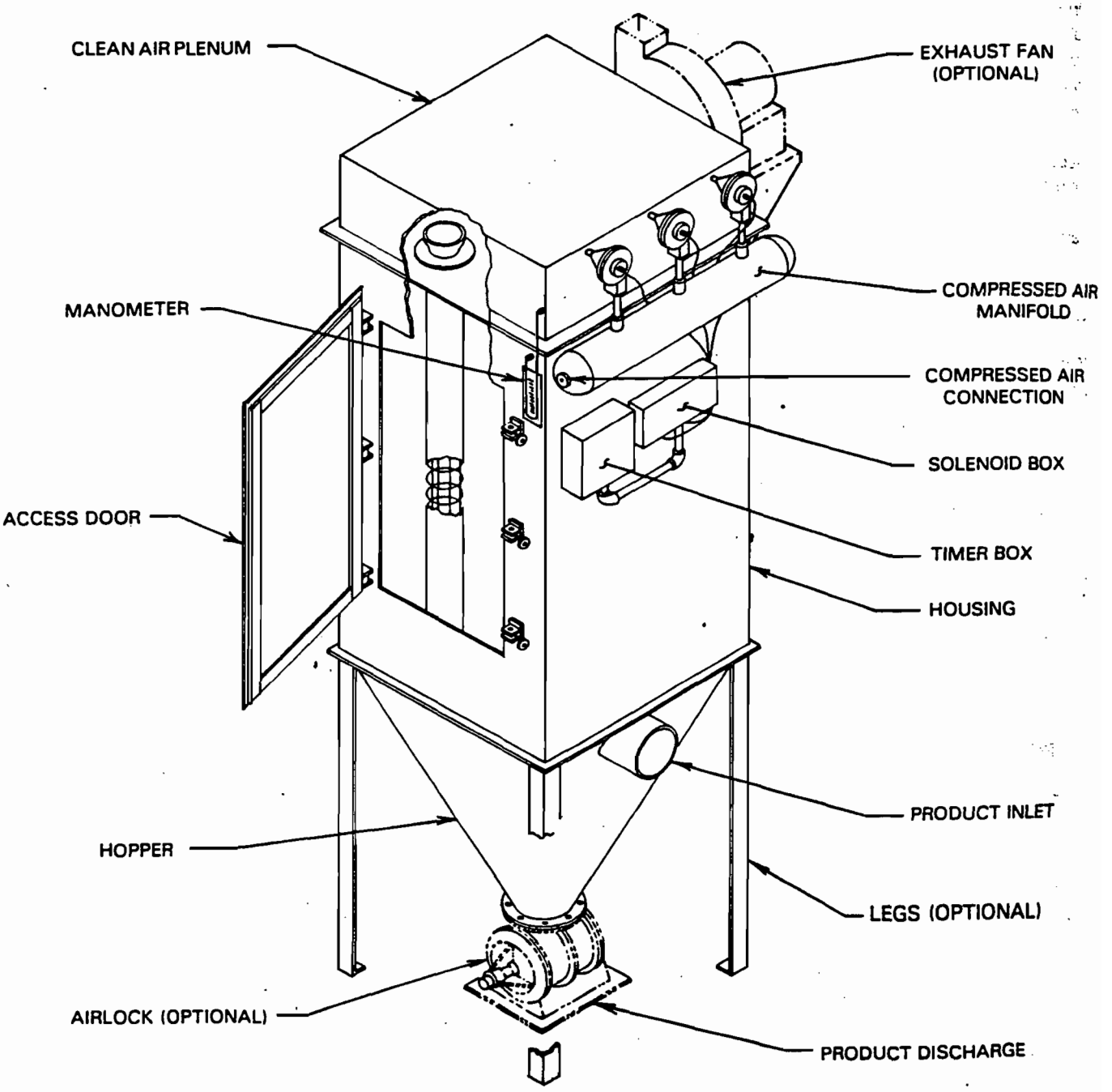


Figure 1 — Super Jet Filter Assembly

APPENDIX A

FUGITIVE EMISSIONS

IDENTIFICATION

Source ID	E.U. ID	Plant Area/ Dept.	Description	S=Significant I=Insignificant P=Presumed Exempt E=Exempt	Reference	Comment
Source ID	E.U. ID	Plant Area/ Dept.	Description	S=Significant I=Insignificant P=Presumed Exempt E=Exempt	Reference	Comment
		YD	Fuel Oil Tanks 1, 2 and 3	I	Dwg 17135-9STU-S1001	No. 6 Fuel. Oil. Tanks 2 less than 350 lb/yr, based on all oil through largest tank.
		YD	Light Oil Tanks 1 and 2 and Fuel Pump	I	Dwg 17135-9STU-S1001	No. 2 Diesel. Tanks 2 less than 800 lb/yr, based on all diesel through largest (CT) tank.
		WT	Water Treatment Processes	P	Dwg 17135-9STU-S1001	Item 27 in DEP letter. Note, however, that if Cl emissions are greater than 10 tons per year, exemption may not apply.
	1	PB	Unit 1 boiler	S	Dwg 17135-9STU-S1001	Shares stack with Unit 2; Natural Gas, No. 6 F.O.; No. 2 F. O.; Tangential Fired
	2	PB	Unit 2 boiler	S	Annual Operating Report RY 1994	Shares stack with Unit 1 Natural Gas, No. 6 F.O.; No. 2 F. O.; Tangential Fired
	3	PB	Unit 3 boiler	S	Dwg 17135-9STU-S1001	Natural Gas, No. 6 Oil; Tangential Fired; single stack.
		YD	Percolation Ponds	P	Dwg 17135-9STU-S1001	
		YD	Valve Stations	P	Dwg 17135-9STU-S1001	Low Vapor Pressure; Methane not a criteria pollutant or VOC.
		YD	Xformers	P	Dwg 17135-9STU-S1001	Sealed
	8	WT	Lime Storage Silo	S	Permit AO05-229996	At Water TXT Bldg, 99% eff., 28.29.32N/80.46.59W; 17-521.5 kmE, 3151.6 kmN; baghouse General Resource Corp., model 13204.8; Loading 2 hr/day; loading rate 10 t/h; 5% opacity; Method 9 30 min annually from Feb 25, 93; vents inside building. May want to modify permit conditions

Source ID	E.U. ID	Plant Area/ Dept.	Description	S=Significant I=Insignificant P=Presumed Exempt E=Exempt	Reference	Comment
CT-A	4	CT	Combustion Turbine (35 MW)	S		H2O/Fuel Min. Table. Simple cycle GE Frame 6 CT, 35 MW cap. Water injection for NOx. BACT, PSD, NSPS; 8760 hrs; 445 MMBtu/hr max @ 59F.; startup 800 HP ICE Diesel, approx 10 min.; max allow /unit/hr. in permit; 5%/10% opacity Nat/Oil; also limited for PSD/inventory CO, PM, PM10, VOC, H2SO4 mist, Beryllium. Dist. Oil S 0.3% wt.
CT-B	5	CT	Combustion Turbine (35 MW)	S		
CT-C	7	CT	Combustion Turbine (129 MW)	S		
CT-D	6	CT	Combustion Turbine (129 MW)	S		
		YD	Propane Tank	P		Pressurized vessel; No longer used.
		PB	Nat. gas Pressure relief valves marked H2	E		CH4 not criteria or HAP
		PB	Lube Oil reservoir vents 115 F	P		Should be Presumptive exempt, if class. as operating equipment vent (Item 18 of DEP letter). Low VP, less than 0.5
		YD	Oil water separators (2)	P		Should be presumptive exempt, based on size, lack of VOCs, and descriptions for Items 23, 27 and 28 in DEP letter. Only reason for VOC would be from diesel spill, which is not normal operating conditions.
		WT	Laboratory Hood	P		Exempt by 62-210.300(3)(n), if used exclusively for chemical or physical analysis.
		MT	Parts washers	E		Exempt -- solvent does not contain VOC or HAPs (i.e., no pollutants). Use non-halogenated solvent only. See also rule 17-213.420(3)(c)3.b.
		MT	Welding	P		Item 18 in DEP letter.
		MT	Bead Blasting	P		Enclosed, Item 2 in DEP letter.
		YD	Unpaved Roads	S		
		YD	Paved Roads	S		

Source ID	E.U. ID	Plant Area/ Dept.	Description	S=Significant I=Insignificant P=Presumed Exempt E=Exempt	Reference	Comment
		PB	Soot Cleanout from Boilers	P		Items 10, 35 in DEP letter.
		PB	CEM equipment	P		Item 15 in DEP letter.
		PB	Generator venting	E		Item 21 in DEP letter.
		WT	Waster Water Effluent Sewage Plant	P		Item 25 in DEP letter.
		YD	Barge No. 6 Fuel Oil Unloading	P		Low vapor pressure, no venting, other than on barge, which is taking in air during unloading. Vapor pressure of No. 6 F.O. is too low for significant levels to bleed through valves and flanges.
		YD	Painting applications for maintenance purposes	S		Item 10 in DEP letter states "Presumptive exemption except for painting/coating applications." Thus, painting for maintenance is not presumed exempt, but must be quanitfied.
		YD	Painting applications for construction purposes	P		Title V is not a construction permit.
		YD	Routine maintenance/repair activities other than painting	P		Item 10 in DEP letter.

APPENDIX B

INSIGNIFICANT ACTIVITIES

Source ID	E.U. ID	Plant Area/ Dept.	Description	S=Significant I=Insignificant P=Presumed Exempt E=Exempt	Reference	Comment
Source ID	E.U. ID	Plant Area/ Dept.	Description	S=Significant I=Insignificant P=Presumed Exempt E=Exempt	Reference	Comment
CT-A	4	CT	Combustion Turbine (35 MW)	S		H2O/Fuel Min. Table. Simple cycle GE Frame 6 CT, 35 MW cap. Water injection for NOx. BACT, PSD, NSPS; 8760 hrs; 445 MMBtu/hr max @ 59F.; startup 800 HP ICE Diesel, approx 10 min.; max allow /unit/hr. in permit; 5%/10% opacity Nat/Oil; also limited for PSD/inventory CO, PM, PM10, VOC, H2SO4 mist, Beryllium. Dist. Oil S 0.3% wt.
CT-B	5	CT	Combustion Turbine (35 MW)	S		
CT-D	6	CT	Combustion Turbine (129 MW)	S		
CT-C	7	CT	Combustion Turbine (129 MW)	S		
	1	PB	Unit 1 boiler	S	Dwg 17135-9STU-S1001	Shares stack with Unit 2; Natural Gas, No. 6 F.O.; No. 2 F. O.; Tangential Fired
	2	PB	Unit 2 boiler	S	Annual Operating Report RY 1994	Shares stack with Unit 1 Natural Gas, No. 6 F.O.; No. 2 F. O.; Tangential Fired
	3	PB	Unit 3 boiler	S	Dwg 17135-9STU-S1001	Natural Gas, No. 6 Oil; Tangential Fired; single stack.
	8	WT	Lime Storage Silo	S	Permit AO05-229996	At Water TXT Bldg, 99% eff., 28.29.32N/80.46.59W; 17-521.5 kmE, 3151.6 kmN; baghouse General Resource Corp., model 13204.8; Loading 2 hr/day; loading rate 10 t/h; 5% opacity; Method 9 30 min annually from Feb 25, 93; vents inside building. May want to modify permit conditions
		YD	Paved Roads	S		
		YD	Painting applications for maintenance purposes	S		Item 10 in DEP letter states "Presumptive exemption except for painting/coating applications." Thus, painting for maintenance is not presumed exempt, but must be quanitfied.
		YD	Unpaved Roads	S		
		MT	Bead Blasting	P		Enclosed, Item 2 in DEP letter.
		MT	Welding	P		Item 18 in DEP letter.
		PB	Lube Oil reservoir vents 115 F	P		Should be Presumptive exempt, if class. as operating equipment vent (Item 18 of DEP letter). Low VP, less than 0.5 mmHg
		PB	Soot Cleanout from Boilers	P		Items 10, 35 in DEP letter.
		PB	CEM equipment	P		Item 15 in DEP letter.
		WT	Laboratory Hood	P		Exempt by 62-210.300(3)(n), if used exclusively for chemical or physical analysis.
		WT	Water Treatment Processes	P	Dwg 17135-9STU-S1001	Item 27 in DEP letter. Note, however, that if Cl emissions are greater than 10 tons per year, exemption may not apply.
		WT	Waster Water Effluent Sewage Plant	P		Item 25 in DEP letter.

Source ID	E.U. ID	Plant Area/ Dept.	Description	S=Significant I=Insignificant P=Presumed Exempt E=Exempt	Reference	Comment
		YD	Routine maintenance/repair activities other than painting	P		Item 10 in DEP letter.
		YD	Oil water separators (2)	P		Should be presumptive exempt, based on size, lack of VOCs, and descriptions for Items 23, 27 and 28 in DEP letter. Only reason for VOC would be from diesel spill, which is not normal operating conditions.
		YD	Painting applications for construction purposes	P		Title V is not a construction permit.
		YD	Propane Tank	P		Pressurized vessel; No longer used.
		YD	Xformers	P	Dwg 17135-9STU-S1001	Sealed
		YD	Valve Stations	P	Dwg 17135-9STU-S1001	Low Vapor Pressure; Methane not a criteria pollutant or VOC.
		YD	Percolation Ponds	P	Dwg 17135-9STU-S1001	
		YD	Barge No. 6 Fuel Oil Unloading	P		Low vapor pressure, no venting, other than on barge, which is taking in air during unloading. Vapor pressure of No. 6 F.O. is too low for significant levels to bleed through valves and flanges.
		YD	Fuel Oil Tanks 1, 2 and 3	I	Dwg 17135-9STU-S1001	No. 6 Fuel. Oil. Tanks 2 less than 350 lb/yr, based on all oil through largest tank.
		YD	Light Oil Tanks 1 and 2 and Fuel Pump	I	Dwg 17135-9STU-S1001	No. 2 Diesel. Tanks 2 less than 800 lb/yr, based on all diesel through largest (CT) tank.
		MT	Parts washers	E		Exempt -- solvent does not contain VOC or HAPs (i.e., no pollutants). Use non-halogenated solvent only. See also rule 17-213.420(3)(c)3.b.
		PB	Generator venting	E		Item 21 in DEP letter.
		PB	Nat. gas Pressure relief valves marked H2	E		CH4 not criteria or HAP

APPENDIX C

ALTERNATIVE METHODS

OF OPERATION

INDIAN RIVER PLANT

ALTERNATIVE METHODS OF OPERATIONS

I. STEAM UNITS

A. UNIT 1

1. Primary Methods

a. Oil

Maximum of 832.2 MMBtu/hr heat input to the boiler from combustion of No. 6 Fuel Oil with minor quantities of No. 2 Fuel Oil used for ignitors.

b. Gas

Maximum of 865.5 MMBtu/hr heat input to the boiler from combustion of pipeline natural gas with minute quantities of No. 2 Fuel Oil used for ingnitors.

c. Mix

Mixture of No. 6 Fuel Oil and Pipeline Natural Gas, both varying in feed rate from 0 to 100% of permitted total heat input.

2. Alternative Methods

a. Landfill Gas

Heat input no more than 10% of permitted heat input on natural gas from landfill waste gas while combusting either No. 6 Fuel Oil or Pipeline Natural Gas.

b. On Spec Used Oil

Heat input no more than 10% of permitted heat input on No. 6 Fuel Oil from on spec used oil while combusting either No. 6 Fuel Oil or Pipeline Natural Gas.

c. Higher Heat Inputs

Heat input from 865.5 MMBtu/hr to 955 MMBtu/hr on gas and from 832.2 MMBtu/hr to 910 MMBtu/hr on No. 6 Fuel Oil. While operating in this method of operation, emission limitations would be reduced by the ratio of the increased heat input (i.e. 865.5/955) so that the emission rate in lbs./hr would remain identical to the permitted rate of the primary method of operation.

B. UNIT 2

1. Primary Methods

a. Oil

Maximum of 2016.5 MMBtu/hr heat input to the boiler from combustion of No. 6 Fuel Oil with minor quantities of No. 2 Fuel Oil used for ignitors.

b. Gas

Maximum of 2248.7 MMBtu/hr heat input to the boiler from combustion of pipeline natural gas with minute quantities of No. 2 Fuel Oil used for ingnitors.

c. Mix

Mixture of No. 6 Fuel Oil and Pipeline Natural Gas, both varying in feed rate from 0 to 100% of permitted total heat input.

2. Alternative Methods

a. Landfill Gas

Heat input no more than 10% of permitted heat input on natural gas from landfill waste gas while combusting either No. 6 Fuel Oil or Pipeline Natural Gas.

b. On Spec Used Oil

Heat input no more than 10% of permitted heat input on No. 6 Fuel Oil from on spec used oil while combusting either No. 6 Fuel Oil or Pipeline Natural Gas.

c. Higher Heat Inputs

Heat input from 2016.5 MMBtu/hr on No. 6 Fuel Oil to 2065 MMBtu/hr on No. 6 Fuel Oil. While operating in this method of operation, emission limitations would be reduced by the ratio of the increased heat input (i.e. 2015.5/2065) so that the emission rate in lbs./hr would remain identical to the permitted rate of the primary method of operation.

C. UNIT 3

1. Primary Methods

a. Oil

Maximum of 3048.8 MMBtu/hr heat input to the boiler from combustion of No. 6 Fuel Oil with minor quantities of No. 2 Fuel Oil used for ignitors.

b. Gas

Maximum of 3208.5 MMBtu/hr heat input to the boiler from combustion of pipeline natural gas with minute quantities of No. 2 Fuel Oil used for ingnitors.

c. Mix

Mixture of No. 6 Fuel Oil and Pipeline Natural Gas, both varying in feed rate from 0 to 100% of permitted total heat input.

2. Alternative Methods

a. Landfill Gas

Heat input no more than 10% of permitted heat input on natural gas from landfill waste gas while combusting either No. 6 Fuel Oil or Pipeline Natural Gas.

b. On Spec Used Oil

Heat input no more than 10% of permitted heat input on No. 6 Fuel Oil from on spec used oil while combusting either No. 6 Fuel Oil or Pipeline Natural Gas.

c. Higher Heat Inputs

Heat input from 3208.5 MMBtu/hr to 3500 MMBtu/hr on gas and from 3048.8 MMBtu/hr to 3350 MMBtu/hr on No. 6 Fuel Oil. While operating in this method of operation, emission limitations would be reduced by the ratio of the increased heat input (i.e. 3208.5/3500) so that the emission rate in lbs./hr would remain identical to the permitted rate of the primary method of operation.

II. COMBUSTION TURBINES

A. COMBUSTION TURBINE A

1. Primary Methods

a. Oil

Maximum of 445 MMBtu/hr heat input into the combustion turbine from No. 2 Fuel Oil.

2. Gas

Maximum of 445 MMBtu/hr heat input into the combustion turbine from Pipeline Natural Gas.

3. Mix

Maximum of 445 MMBtu/hr heat input from a mixture of 0 to 100% No. 2 Fuel Oil and 0 to 100% Pipeline Natural Gas

B. COMBUSTION TURBINE B

1. Primary methods

a. Oil

Maximum of 445 MMBtu/hr heat input into the combustion turbine from No. 2 Fuel Oil.

2. Gas

Maximum of 445 MMBtu/hr heat input into the combustion turbine from Pipeline Natural Gas.

3. Mix

Maximum of 445 MMBtu/hr heat input from a mixture of 0 to 100% No. 2 Fuel Oil and 0 to 100% Pipeline Natural Gas

C. COMBUSTION TURBINE C

1. Primary Methods

a. Oil

Maximum of 1346 MMBtu/hr heat input into the combustion turbine from No.

2 Fuel Oil.

2. Gas

Maximum of 1354 MMBtu/hr heat input into the combustion turbine from Pipeline Natural Gas.

3. Mix

Maximum of between 1354 and 1346 MMBtu/hr heat input from a mixture of 0 to 100% No. 2 Fuel Oil and 0 to 100% Pipeline Natural Gas

D. COMBUSTION TURBINE D

1. Primary Methods

a. Oil

Maximum of 1346 MMBtu/hr heat input into the combustion turbine from No. 2 Fuel Oil.

2. Gas

Maximum of 1354 MMBtu/hr heat input into the combustion turbine from Pipeline Natural Gas.

3. Mix

Maximum of between 1354 and 1346 MMBtu/hr heat input from a mixture of 0 to 100% No. 2 Fuel Oil and 0 to 100% Pipeline Natural Gas

III. LIME SILO

1. Primary Method

A. Permitted Rates

Current permit allows for lime to be fed at 10 tph for 2 hours per day.

2. Alternative Method

B. Increased Feed Rates

Lime feed rate of 15 tph for up to 4 hours/day while maintaining permitted limit of 5% opacity.

APPENDIX D

COMPLIANCE PLAN AND REPORT

COMPLIANCE REPORT and PLAN

EMISSIONS UNIT	IN COMPLIANCE *	OUT OF COMPLIANCE
01 BOILER 1	X	
02 BOILER 2	X	
03 BOILER 3	X	
04 COMBUSTION TURBINE A	X	
05 COMBUSTION TURBINE B	X	
06 COMBUSTION TURBINE C	X	
07 COMBUSTION TURBINE D	X	
08 LIME STORAGE SILO	X	
No ID NON-REGULATED EMISSIONS (EX. & INSIG)	X	
No ID NON-REGULATED EMISSIONS (SIGNIFICANT)	X	

* In compliance with all applicable regulations and requirements listed in Section II. Part 3b and Section III. Part 6b of the application.

APPENDIX E

COMPLIANCE STATEMENT

Compliance Certification (Hard-copy Required):

"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 the compliance report found in Appendix D are true, accurate, and complete."

Gregory A. DeMuth
Director
Environmental Division

6/14/96
Date

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

October 26, 1993

U. S. Environmental
Protection Agency
Region IV
345 Courtland Street, N. E.
Atlanta, GA 30365

Florida Department of
Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32301

Gentlemen:

This letter shall be the letter of authorization for Gregory A. DeMuth, Director Environmental Division for the Orlando Utilities Commission, to sign reports on behalf of the Orlando Utilities Commission as they relate to the Environmental Protection Agency and the Florida Department of Environmental Protection permits to operate and/or construct pollution sources.

Sincerely,

Troy W Todd

Troy W. Todd
General Manager and CEO

TWT:rc
authoriz

APPENDIX F

FUEL SPECIFICATIONS

FUEL SPECIFICATIONS

1.NO. 6 FUEL OIL	Density	0.9 - 1.0 s.g.
	Heat Value	6.2 - 6.4 MMBtu/bbl..
	% S	0.9 - 2.5%
	% N	< 0.5%
	% Ash	0.09 - 0.12
2. PIPELINE NATURAL GAS	Density	0.4 - 0.6 rel.
	Heat Value	980 - 1060 Btu/scf
	% S	< 1%
	% N	< 0.5%
	% Ash	< 1%
3. NO. 2 FUEL OIL	Density	0.9 - 1.0 s.g.
	Heat Value	5.0 - 5.75 MMBtu/bbl..
	% S	0.25 - 0.3%
	% N	< 0.5%
	% Ash	0.15% - 0.25%
4. LANDFILL WASTE GAS	Density	0.4 - 0.6 rel
	Heat Value	500 Btu/scf
	% S	< 1%
	% N	< 0.5%
	% Ash	< 1%
5. ON SPEC USED OIL	Density	0.9 - 1.0 s.g.
	Heat Value	4.5 - 5.5 MMBtu/bbl..
	% S	< 1%
	% N	< 0.5%
	% Ash	< 1%
6. MAGNESIUM HYDROXIDE (additive)		
	Density	1.3 - 1.5 s.g.
	Heat Value	0 MMBtu/gal.
	% S	< 1%
	% N	< 1%
	% Ash	< 1%

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

Certified Mail No. Z-215-203-287
Return Receipt Requested

November 15, 1995

Mr. Charles M. Collins, P. E.
Program Administrator Air Section
Florida Department of
Environmental Protection
3319 Maguire Blvd., Suite 232
Orlando, FL 32803

Dear Mr. Collins:

On September 28, 1995, particulate emission tests were completed to re-verify compliance with the state regulations on the No. 1 boiler at the Indian River Plant, Operating Permit Number AO-05-183384 Unit 1. The heat input during these tests was approximately 775 M^2BTU/hour.

The results, as tabulated below, show the unit to be in compliance with the State of Florida regulations of 0.1 lb/M^2BTU during steady state and 0.3 lb/M^2BTU during soot-blowing operation.

Run No.	Particulate Emission (lb./10^6BTU)	Percent Iso-Kinetics	Average Visible Emissions (% Opacity)
		STEADY STATE	
1	0.049	101.4	
5	0.037	99.2	
6	0.036	100.7	
Avg.	0.041	100.4	7.1%

APPENDIX G

COMPLIANCE TEST REPORTS

Run No.	Particulate Emission (lb./10^6BTU)	Percent Iso-Kinetics	Average Visible Emissions (% Opacity)
		SOOT-BLOWING	
2	0.030	100.8	
3	0.073	103.2	
4	0.024	99.7	
Avg.	0.042	101.2	2.7%

The on-line sample of the fuel burned during the test shows the sulfur content as 0.81% which calculates to be an emission rate of 0.88 lbs/M^2BTU, well below the 2.75 lbs^2/M BTU permitted by the Florida standard.

Attached is the test report for the compliance test prepared by Air Consulting & Engineering, Inc.

If you have any questions, please call me at 423-9133.

Sincerely,

Robert F. Hicks
Sr. Environmental Engineer

RFH:rc
Attachment

xc: F. F. Haddad
G. M. Standridge
G. A. DeMuth
V. F. Gallucci w/enclosure

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Table 1 Particulate Emissions Summary
Orlando Utilities Commission
Indian River Plant - Unit 1
Sharpes, Florida
September 1995

Run Number	Time	Flow Rate		Stack Temp	Moisture	Oxygen	Emission Rate	
		Actual (ACFM)	Standard (SCFMD)	(°F)	(%)	(%)	Actual (lbs/MMBTU)	Allowable (lbs/MMBTU)
Normal Operating Mode								
1	9/27/95 1750-1905	271572	172478	294	9.9	6.4	0.04892	0.1
5	9/28/95 1112-1242	295051	183494	304	10.1	6.5	0.03709	0.1
6	9/28/95 1252-1406	289630	178843	304	10.8	6.4	0.03559	0.1
Normal Mode Average		285418	178272	301	10.3	6.4	0.04053	0.1
Soot Blowing Mode								
2	9/27/95 1919-2033	273206	174245	289	10.1	6.6	0.03029	0.3
3	9/28/95 0832-0948	286993	179472	294	10.8	6.7	0.07254	0.3
4	9/28/95 1000-1115	296194	184575	301	10.2	6.6	0.02430	0.3
Average		285464	179431	295	10.4	6.6	0.04238	0.3

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

Certified Mail No. Z-215-203-288
Return Receipt Requested

November 15, 1995

Mr. Charles M. Collins, P. E.
Program Administrator Air Section
Florida Department of
Environmental Protection
3319 Maguire Blvd., Suite 232
Orlando, FL 32803

Dear Mr. Collins:

On September 25, 1995, particulate emission tests were completed to re-verify compliance with the state regulations on the No. 2 boiler at the Indian River Plant, Operating Permit Number AO 05-183384 Unit 2. The heat input during these tests was approximately 1915 M^2BTU/hour.

The results, as tabulated below, show the unit to be in compliance with the State of Florida regulations of 0.1 lb/M^2BTU during steady state and 0.3 lb/M^2BTU during soot-blowing operation.

Run No.	Particulate Emission (lb./10^6BTU	Percent Iso-Kinetics	Average Visible Emissions (% Opacity)
		STEADY STATE	
1	0.023	101.3	
5	0.026	102.2	
6	0.048	101.1	
Avg.	0.032	101.5	7.5%

Run No.	Particulate Emission (lb./10^6BTU	Percent Iso-Kinetics	Average Visible Emissions (% Opacity)
		SOOT-BLOWING	
2	0.107	101.4	
3	0.060	100.3	
4	0.055	102.3	
Avg.	0.074	101.2	13.1%

The on-line sample of the fuel burned during the test shows the sulfur content as 0.82% which calculates to be an emission rate of 0.89 lbs/M^2BTU, well below the 2.75 lbs/M^2 BTU permitted by the Florida standard.

Attached is the test report for the compliance test prepared by Total Source Analysis, Inc.

If you have any questions, please call me at 423-9133.

Sincerely,

Robert F. Hicks
Sr. Environmental Engineer

RFH:rc
Attachment

xc: F. F. Haddad
G. M. Standridge
G. A. DeMuth
V. F. Gallucci w/enclosure

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Table 1 Particulate Emissions Summary
Orlando Utilities Commission
Indian River Plant - Unit 2
Sharpes, Florida
September 25, 1995

Run Number	Time	Flow Rate		Stack Temp	Moisture	Oxygen	Emission Rate	
		Actual (ACFM)	Standard (SCFMD)	(°F)	(%)	(%)	Actual (lbs/MMBTU)	Allowable (lbs/MMBTU)
Normal Operating Mode								
1	0710-0822	885422	536425	328	9.7	7.1	0.02295	0.1
5	1256-1406	909905	542477	336	10.4	6.9	0.02599	0.1
6	1424-1534	936994	560288	336	10.1	6.9	0.04793	0.1
Normal Mode Average		910774	546397	333	10.1	7.0	0.03229	0.1
Soot Blowing Mode								
2	0838-0947	868047	515933	330	11.1	7.3	0.10728	0.3
3	1004-1114	896642	531851	333	11.0	7.2	0.06025	0.3
4	1128-1238	902159	536329	333	10.9	7.0	0.05522	0.3
Average		888949	528038	332	11.0	7.2	0.07425	0.3

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

Certified Mail No. Z-215-203-289
Return Receipt Requested

November 15, 1995

Mr. Charles M. Collins, P. E.
Program Administrator Air Section
Florida Department of
Environmental Protection
3319 Maguire Blvd., Suite 232
Orlando, FL 32803

Dear Mr. Collins:

On September 27,1995, particulate emission tests were completed to re-verify compliance with the state regulations on the No. 3 boiler at the Indian River Plant, Operating Permit Number AO 05-183384 Unit 3. The heat input during these tests was approximately 2550 M^2BTU/hour.

The results, as tabulated below, show the unit to be in compliance with the State of Florida regulations of 0.1 lb/M^2BTU during steady state and 0.3 lb/M^2BTU during soot-blowing operation.

Run No.	Particulate Emission (lb./10^6BTU	Percent Iso-Kinetics	Average Visible Emissions (% Opacity)
		STEADY STATE	
1	0.048	105.0	
4	0.021	103.6	
5	0.054	104.3	
Avg.	0.041	104.3	10.6%

Run No.	Particulate Emission (lb./10^6BTU	Percent Iso-Kinetics	Average Visible Emissions (% Opacity)
		SOOT-BLOWING	
2	0.076	104.0	
3	0.083	104.5	
6	0.080	104.1	
Avg.	0.080	104.2	17.3%

The on-line sample of the fuel burned during the test shows the sulfur content as 0.92% which calculates to be an emission rate of 1.00 lbs/M^2BTU, well below the 2.75 lbs^2/M BTU permitted by the Florida standard.

Attached is the test report for the compliance test prepared by Total Source Analysis, Inc.

If you have any questions, please call me at 423-9133.

Sincerely,

Robert F. Hicks
Sr. Environmental Engineer

RFH:rc
Attachment

xc: F. F. Haddad
G. M. Standridge
G. A. DeMuth
V. F. Gallucci w/enclosure

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Table 1 Particulate Emissions Summary
Orlando Utilities Commission
Indian River Plant - Unit 3
Sharpes, Florida
September 1995

Run Number	Time	Flow Rate		Stack Temp (°F)	Moisture (%)	Oxygen (%)	Emission Rate	
		Actual (ACFM)	Standard (SCFMD)				Actual (lbs/MMBTU)	Allowable (lbs/MMBTU)
Normal Operating Mode								
1	9/26/95 1100-1207	945741	586690	306	10.6	5.7	0.04789	0.1
4	9/26/95 1503-1609	964400	597365	308	10.5	5.5	0.02116	0.1
5	9/27/95 0930-1035	979311	602310	308	11.0	5.7	0.05413	0.1
Normal Mode Average		963142	595455	307	10.7	5.6	0.04106	0.1
Soot Blowing Mode								
2	9/26/95 1222-1327	953782	590961	307	10.6	5.7	0.07578	0.3
3	9/26/95 1342-1447	956762	594477	308	10.3	5.8	0.08342	0.3
6	9/27/95 1052-1156	963017	590807	309	11.1	5.7	0.07964	0.3
Average		957854	592082	308	10.7	5.7	0.07961	0.3

ORLANDO UTILITIES COMMISSION
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Certified Letter No. Z-215-203-431
Return Receipt Requested

April 22, 1996

Mr. Leonard Kozlov, P. E., Administrator
Air Resources Management
Florida Department of Environmental Protection
3319 Maguire Boulevard - Suite 232
Orlando, FL 32803

Re: Annual Emissions Test Report
Combustion Turbines A & B
DER Permit No. A005-176351

Dear Mr. Kozlov:

Attached is the Fiscal Year 1996 Annual Emissions Test report for the above referenced units.

These tests were conducted in order to fulfill the requirements found in Specific Condition 10 of the applicable permit. Neither unit accumulated 170 hours burning fuel oil during the preceding 12 months period; therefore, tests were conducted using natural gas only.

The Lower Heating Value (LHV), as calculated from the gas analysis supplied by Florida Gas, was 947 BTU/CuFt. Average ambient temperature during CT-A and CT-B tests was 82°F and 69.5°F respectively. The allowable heat input at these temperatures is determined to be 410.7 MMBTU/HR for CT-A and 429.4 MMBTU/HR for CT-B. Based on these values from the attached "HEAT INPUT vs TEMPERATURE" curve (See Attachment A), CT-A was operating at 385.2 MMBTU/HR or 93.8% of the allowable heat input and CT-B was operating at 401 MMBTU/HR or 93.4% of the allowable heat input.

If you have any questions, please call me at 423-9133.

Sincerely,

Robert F. Hicks
Sr. Environmental Engineer

RFH:rc
Attachment

xc: G. A. DeMuth
V. F. Gallucci
J. M. Kraus, w/attach.

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Table 1 NOx Emissions and Operating Parameter Summary
Combustion Turbines A and B
Indian River Plant
Orlando Utilities Commission
February 20, 1996

Run Number	Load MW	Gaseous Fuel Flow Rate lbs/sec	HHV Heat Input MMBTU/Hr	Water to Fuel Ratio	NOx ppm	O2 %	NOx lbs/Hr
Unit A - 1	—	—	—	—	49.82	14.84	76.25
2	—	—	—	—	46.33	14.83	70.77
3	—	—	—	—	43.02	14.92	66.69
Average	34.31	5.13	426.68	0.593	46.39	14.86	71.24
Unit B - 1	—	—	—	—	35.89	14.76	56.41
2	—	—	—	—	32.51	14.74	50.98
3	—	—	—	—	31.55	14.87	48.56
Average	35.61	5.34	444.14	0.77	33.32	14.79	51.98

HHV = 1048.9 BTU/ft^3

Gas Density* = $\frac{28.84\ g}{22.4} \times \frac{492}{520} \times \frac{lb}{453.6\ g} \times \frac{28.32\ liters}{ft3}$ = 0.076 lbs/SCF for standard air

0.076 lbs/SCF x S.G. = 0.076 lbs/SCF x 0.5973 = 0.454 lbs/SCF

BTU/Hr = (fuel flow) $\frac{3600\ sec.}{Hr}$ (1048.9 BTU/ft3) $\frac{1}{0.0454\ lbs/SCF}$

*1 mole of a gas occupies 22.4 liters at zero degrees C and 29.92 "Hg

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

Via Hand Delivery

December 21, 1995

Ms. Vivian Garfein
Central District Director
Florida Department of
Environmental Protection
3319 Maguire Blvd., Suite 232
Orlando, FL 32803

Re: Orlando Utilities Commission's Indian River Plant
Combustion Turbines C & D

Dear Ms. Garfein:

We have now completed all remedial activities agreed upon at our meeting on September 20, 1995 and as outlined in my letter to you on September 27, 1995. The modifications were completed by Westinghouse as scheduled: fuel oil flow meters were recalibrated, new water injection control curves were established, alarms were hard wired to the main control room, and compliance tests were performed to verify combustion turbines' performance.

The water injection control curves which were established are found in Attachment 1. For each combustion turbine, two curves were established for each fuel. The curve of the water/fuel ratio vs. fuel flow which would result in NOx emissions at the permitted limit was determined. This curve must not be exceeded in order to maintain continuous compliance. In addition, a second more conservative water/fuel vs. fuel flow curve was established to be used as the control curve, which will allow some variation from the control curve without causing an exceedance of the emissions limit.

Also enclosed, is the Compliance Test Report covering the Annual 1995 compliance tests which were conducted on November 7 and 9, 1995, demonstrating the units are operating below the required emissions limits.

We wish to express our appreciation to the Department and especially to Anatoly Sobolevsky for the cooperation extended during the implementation of these remedial activities for Cts C and D. We believe we now have a monitoring system and control curves based on good engineering data which will allow these turbines to both operate and demonstrate full compliance with the applicable regulations.

If you have any questions, please call me at 423-9141 or Bob Hicks at 423-9133.

Very truly yours,

Gregory A. DeMuth
Director
Environmental Division

GAD:rc
enclosures

xc: G. M. Standridge
F. F. Haddad
V. G. Gallucci
R. F. Hicks
J. M. Kraus, w/enclosures
A. Sobolevsky, FDEP

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Table 1 Gas Turbine Emission Summary
Combustion Turbine – Unit CT-C - Natural Gas Firing
Indian River Power Plant
Orlando Utilities Commission
Frontenac, Florida
November 9, 1995

Run Number	Time	Power MW Ratio	Water/Fuel Ratio	Oxygen %	NOx Emissions ppm	NOx Emissions ppm @ 15% O2	NOx Emissions ISO ppm	CO Emissions ppm	VE %
1	1249-1351	114	1.17	14.31	27.72	24.82	24.02	4.1	
2	1406-1508	114	1.17	14.36	23.37	21.09	20.39	8.4	
3	1502-1624	114	1.17	14.31	24.41	21.81	21.09	8.2	
AVERAGE		114	1.17	14.3	25.2	22.6	21.8	6.9	0
1	1133-1149	81	1.11	16.10	17.35	21.32	20.76		
2	1148-1204	81	1.11	16.24	17.36	21.97	21.33		
3	1211-1227	81	1.11	16.30	17.46	22.40	21.76		
AVERAGE		81	1.11	16.20	17.4	21.9	21.1		0
1	0941-0957	56	1.12	17.17	14.05	22.25	21.74		
2	1007-1023	56	1.12	17.28	14.18	23.13	22.58		
3	1027-1043	56	1.12	17.29	14.11	23.02	22.46		
AVERAGE		56	1.12	17.25	14.11	22.8	22.26		0
1	0705-0739	38	1.22	18.11	10.69	22.60	22.25		
2	0748-0820	38	1.22	18.01	11.43	23.37	23.09		
3	0826-0909	38	1.22	18.04	10.99	22.67	22.36		
AVERAGE		38	1.22	18.0	11.0	22.9	22.6		0

Allowable NO_x emissions = 25 ppm$_v$ @ 15% O_2
Allowable CO emissions = 25 ppm$_v$
Allowable VE emissions = 10% opacity at full load
= 20% opacity at other loads

Table 2 Gas Turbine Emission Summary
Combustion Turbine – Unit CT-D - Natural Gas Firing
Indian River Power Plant
Orlando Utilities Commission
Frontenac, Florida
November 7, 1995

Run Number	Time	Load MW	Water/Fuel Ratio	Oxygen %	NOx Emissions ppm	NOx Emissions ppm @ 15% O2	NOx Emissions ISO ppm	CO Emissions ppm	VE %
1	1322-1424	107	1.13	14.36	24.31	21.92	23.95	7.1	
2	1435-1537	107	1.13	14.33	25.98	23.31	25.10	6.2	
3	1509-1611	107	1.13	14.16	27.60	24.14	25.99	3.6	
AVERAGE		107	1.13	14.3	26.0	23.1	25.0	5.6	0
1	1100-1126	81	1.01	15.83	21.32	24.80	26.85		
2	1134-1150	81	1.01	15.81	21.39	24.77	27.02		
3	1157-1213	81	1.01	15.80	21.63	25.01	27.21		
AVERAGE		81	1.01	15.8	21.4	24.9	27.0		0
1	0929-0945	55	1.07	17.10	14.13	21.94	24.63		
2	0953-1009	55	1.07	17.09	14.24	22.04	24.84		
3	1021-1037	55	1.07	17.10	14.11	21.92	24.62		
AVERAGE		55	1.07	17.10	14.2	22.0	24.7		0
1	0708-0743	39	1.16	17.92	10.09	19.98	22.42		
2	0752-0822	39	1.16	17.78	10.61	20.10	22.74		
3	0831-0913	39	1.16	17.87	11.16	21.71	24.67		
AVERAGE		39	1.16	17.9	10.6	20.6	23.3		0

Allowable NO_x emissions = 25 ppm_v @ 15% O_2
Allowable CO emissions = 25 ppm_v
Allowable VE emissions = 10% opacity at full load
= 20% opacity at other loads

BAGHOUSE COMPLIANCE REPORT

EPA

VISIBLE EMISSION OBSERVATION FORM 1

Form Number: 0001 | Page: 1 Of 1

Continued on VEO Form Number:

Method Used (Circle One): Method 9 | 203A | 203B | Other: _____

Company Name: Orlando Utilities Commission

Facility Name: Indian River Plant

Street Address: 7800 S. US Hwy #1

City: Titusville | State: FL | Zip: 32780

Process: Lime Silo | Unit #: | Operating Mode:

Control Equipment: Baghouse | Operating Mode:

Describe Emission Point: Vent 35' off grade

Height of Emiss. Pt. Start: 45' End: 90'

Height of Emiss. Pt. Rel. to Observer, Start: 30' End: 3'

Distance to Emiss. Pt. Start: 50' End: 50'

Direction to Emiss. Pt. (Degrees) Start: _____ End: _____

Vertical Angle to Obs. Pt. Start: 55° End: 35°

Direction to Obs. Pt. (Degrees) Start: 270° End: 270°

Distance and Direction to Observation Point from Emission Point Start: 50', 90° End: 50', 90°

Describe Emissions Start: None End: None

Emission Color Start: None End: None

Water Droplet Plume: Attached ☐ Detached ☐ None ☒

Describe Plume Background Start: None End: None

Background Color Start: grey End: grey

Sky Conditions Start: P.C. End: P.C.

Wind Speed Start: 0-5 End: 0-5

Wind Direction Start: 270 End: 270

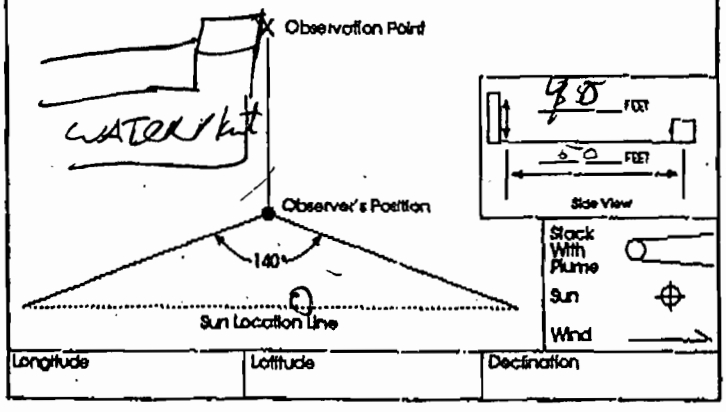
Ambient Temp. Start: 84°F End: 85°F

Wet Bulb Temp.: —

RH Percent:

Source Layout Sketch

Draw North Arrow: ☐TN ☒MN



Longitude: | Latitude: | Declination:

Additional Information:

Observation Date	Time Zone	Start Time	End Time
		1550	1920

Sec / Min	0	15	30	45	Comments
1	0	0	0	0	
2	0	0	0	0	
3	0	0	0	0	
4	0	0	0	0	
5	0	0	0	0	
6	0	0	0	0	
7	0	0	0	0	
8	0	0	0	0	
9	0	0	0	0	
10	0	0	0	0	
11	0	0	0	0	
12	0	0	0	0	
13	0	0	0	0	
14	0	0	0	0	
15	0	0	0	0	
16	0	0	0	0	
17	0	0	0	0	
18	0	0	0	0	
19	5	5	0	0	
20	5	5	5	0	
21	5	5	5	0	
22	5	5	5	5	
23	0	5	5	0	
24	0	5	5	0	
25	10	5	5	0	
26	5	0	5	0	
27	0	0	0	0	
28	5	5	0	0	
29	5	5	0	0	
30	0	5	0	5	

Observer's Name (Print): JASON M. KRAUS

Observer's Signature: [signature] Date: 6/12/96

Organization: OUC

Certified By: ETA Date: 6/20/96

APPENDIX H

PROCEDURES FOR

STARTUP, SHUTDOWN AND

OPERATION AND MAINTENANCE PLAN

ORLANDO UTILITIES COMMISSION

INDIAN RIVER PLANT

OPERATION AND MAINTENANCE MANUAL

PURPOSE:

To ensure the correct, safe operation and maintenance of plant equipment and systems. This manual shall provide procedures for operating and maintaining plant equipment during periods of start-up, shutdown and malfunction.

APPLICABILITY:

The procedures set forth in this plan only pertain to those items directly related to the generation and control of emissions.

PROCEDURES:

Contained at the facility are manuals provided by the OEM (Original Equipment Manufacturer) that specify the proper operation and maintenance of each piece of equipment and systems. As these manuals are voluminous, they are only referenced in this plan. These manuals provide detailed specifications for all phases of operation and maintenance including start-up, shutdown and malfunction of this equipment.

Operators use data from the continuous emissions monitoring systems to minimize excess emissions during start-up, shutdown, malfunction and normal plant operation. If excess emissions are detected, the proper plant personnel are notified and corrective actions are taken such as performing maintenance on an item, adjusting the controls or shedding load off the unit. Recurring problems are addressed using best management practices.

TRAINING:

Plant operations personnel first begin as apprentices, where they are allowed time to learn plant systems under the expertise of a trained plant operator. Over time, they are taught the best operational practices for each system and piece of equipment. Additionally, each operator continues training throughout his/her career through use of the NUS Power Plant Operations and Power Plant Maintenance series. Promotions are contingent upon the successful completion of each phase of this series and failure to successfully complete the training may result in demotion. Training records are maintained at the facility.

Maintenance personnel also begin as an apprentice, working under the supervision of trained maintenance personnel. Their progression is also dependant upon successful completion of the NUS Power Plant Maintenance series. Training records are maintained at the facility.

MAINTENANCE PLANNING:

The facility uses a computerized maintenance scheduler that generates work orders based upon OEM recommendations. All work orders are completed based upon a variety of factors such as the last time the work order was completed, the availability of plant

resources or the cost to complete the work order. Furthermore, work orders may be deferred until the next scheduled outage. Additionally, maintenance is completed on an as needed basis, due to emergencies and equipment failure.

Maintenance records are kept at the facility for each work order and trouble report. Maintenance history for each system or large piece of equipment is also available.

APPENDIX I

ACID RAIN APPLICATIONS

PHASE II PERMIT APPLICATION

Page

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 214, F.A.C.

This submission is: [X] New [ ] Revised

Step 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name	State	ORIS Code
Indian River Plant	FI	683

Step 2
Enter the boiler ID# from NADB for each affected unit, and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e

a	Compliance Plan		d	e
Boiler ID#	b Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	c Repowering Plan	d New Units Commence Operation Date	e New Units Monitor Certification Deadline
1	Yes	No		
2	Yes	No		
3	Yes	No		
C	Yes	No	01 Sep 1992	01 Jan 1995
D	Yes	No	01 Oct 1992	01 Jan 1995
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "yes" for any unit

[ ] For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

Plant Name (from Step 1)

Indian River Plant

Step 4
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

Permit Requirements:

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72, Rules 62-214.320 and 330, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary to review an Acid Rain part application and issue or deny an Acid Rain permit;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the permitting authority; and
(ii) Have an Acid Rain Part.

Monitoring Requirements:

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measured recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor the emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements:

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances , as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certificationunder 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements: The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements:

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements:

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certification of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Plant Name (from Step 1)

Indian River Plant

Recordkeeping and Reporting Requirements (cont.)

(iv) Copies of all documents used to complete an Acid Rain part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability:

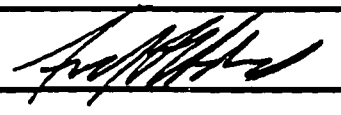
(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or written exemption under 40 CFR 72.7 or 72.8, including any requirement for payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 including 40 CFR 75.16, 75.17, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40CFR parts 72, 73, 75, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities: No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any provision of the Act, including the provisions of title I of the Act relating to applicable National Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudent review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalities for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name: Fred F. Haddad, Jr.	
Signature: 	Date: 12/15/95

APPENDIX J

DESCRIPTION OF

CONTROL EQUIPMENT

CONTROL EQUIPMENT

1. COMBUSTION TURBINE A

Combustion Turbine A employs water injection to control NOx emissions. Emissions limits are set at 75.1 lb/hr while combusting Pipeline Natural Gas and at 118.3 lb/hr while combusting No. 2 Fuel oil, at sea level and 59F. Water injection rates are programmed to ensure that these emission rates are not exceeded.

2. COMBUSTION TURBINE B

Combustion Turbine B employs water injection to control NOx emissions. Emissions limits are set at 75.1 lb/hr while combusting Pipeline Natural Gas and at 118.3 lb/hr while combusting No. 2 Fuel oil, at sea level and 59F. Water injection rates are programmed to ensure that these emission rates are not exceeded.

3. COMBUSTION TURBINE C

Combustion Turbine C employs water injection to control NOx emissions. Emissions limits are set at 25 ppmvd while combusting Pipeline Natural Gas and at 42 ppmvd while combusting No. 2 Fuel oil, 15% oxygen. Water injection rates are programmed to ensure that these emission rates are not exceeded.

4. COMBUSTION TURBINE D

Combustion Turbine D employs water injection to control NOx emissions. Emissions limits are set at 25 ppmvd while combusting Pipeline Natural Gas and at 42 ppmvd while combusting No. 2 Fuel oil, 15% oxygen. Water injection rates are programmed to ensure that these emission rates are not exceeded.

5. LIME STORAGE SILO

The Lime Storage Silo uses a fabric filter baghouse during lime feed operations to control particulate emissions. This filter is approximately 99% efficient in particulate matter removal.

APPENDIX K

ADDITIONAL RULES

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
[a]This list includes only those applicable requirements typically associated with an electric power plant. For example, NSPS Subpart O for sewage treatment plants has not been included. If rules other than those listed herein apply to your source, they should be included in your source's application even if they are not listed below. [b]Please refer to HGSS's June 6, 1995 memorandum explaining how this list was developed and how applicable requirements should be addressed in an application.						
Part 60 - EPA Regulations on Standards of Performance for New Stationary Sources						
Subpart A — General Provisions						
60.7	Notification and record keeping.	004, 005, 006, 007	X			Unit
60.8	Performance tests.	004, 005, 006, 007	X			Unit
60.11	Compliance with standards and maintenance requirements.	004, 005, 006, 007	X			Unit
60.12	Circumvention.	004, 005, 006, 007	X			Unit
60.13	Monitoring requirements.	004, 005, 006, 007	X			Unit
60.19	General notifications and reporting requirements.	004, 005, 006, 007	X			Unit
Subpart D — Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971						
60.42	Standard for particulate matter.			X		Unit
60.43	Standard for sulfur dioxide.			X		Unit
60.44	Standard for nitrogen oxides.			X		Unit
60.45	Emission and fuel monitoring.			X		Unit
60.46	Test methods and procedures.			X		Unit
Subpart Da — Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978						

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
60.42a	Standard for particulate matter.			X		Unit
60.43a	Standard for sulfur dioxide.			X		Unit
60.44a	Standard for nitrogen oxides.			X		Unit
60.45a	Commercial demonstration permit.			X		Unit
60.46a	Compliance provisions.			X		Unit
60.47a	Emission monitoring.			X		Unit
60.48a	Compliance determination procedures and methods.			X		Unit
60.49a	Reporting requirements.			X		Unit
Subpart Db — Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units						
60.42b	Standard for sulfur dioxide.			X		Unit
60.43b	Standard for particulate matter.			X		Unit
60.44b	Standard for nitrogen oxides.			X		Unit
60.45b	Compliance and performance test methods and procedures for sulfur dioxide.			X		Unit
60.46b	Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.			X		Unit
60.47b	Emission monitoring for sulfur dioxide.			X		Unit
60.48b	Emission monitoring for particulate matter and nitrogen oxides.			X		Unit
60.49b	Reporting and recordkeeping.			X		Unit
Subpart Dc — Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units						
N60.42c	Standard for sulfur dioxide.			X		Unit
60.43c	Standard for particulate matter.			X		Unit

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
60.44c	Compliance and performance test methods and procedures for sulfur dioxide.			X		Unit
60.45c	Compliance and performance test methods and procedures for particulate matter.			X		Unit
60.46c	Emission monitoring for sulfur dioxide.			X		Unit
60.47c	Emission monitoring for particulate matter.			X		Unit
60.48c	Reporting and recordkeeping.			X		Unit
Subpart K — Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978						
60.112	Standard for volatile organic compounds (VOC).			X		Unit
60.113	Monitoring of operations.			X		Unit
Subpart Ka — Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984						
60.112a	Standard for volatile organic compounds (VOC).			X		Unit
60.113a	Testing and procedures.			X		Unit
60.114a	Alternative means of emission limitations.			X		Unit
60.115a	Monitoring of operations.			X		Unit
Subpart Kb — Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984						
60.112b	Standard for volatile organic compounds (VOC).			X		Unit
60.113b	Testing and procedures.			X		Unit
60.114b	Alternative means of emission limitations.			X		Unit
60.115b	Recordkeeping and reporting requirements.			X		Unit
60.116b	Monitoring of operations.			X		Unit

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
Subpart Y — Standards of Performance for Coal Preparation Plants						
60.252	Standard for particulate matter.			X		Unit
60.253	Monitoring of operations.			X		Unit
60.254	Test methods and procedures.			X		Unit
Subpart GG — Standards of Performance for Stationary Gas Turbines						
60.332	Standard for nitrogen oxides.	006, 007	X			Unit
60.333	Standard for sulfur dioxide.	006, 007	X			Unit
60.334	Monitoring of operations.	006, 007	X			Unit
60.335	Test methods and procedures.	006, 007	X			Unit
Subpart OOO — Standards of Performance for Nonmetallic Mineral Processing Plants						
60.672	Standard for Particulate Matter.			X		Unit
60.674	Monitoring of Operations.			X		Unit
60.676	Reporting and Recordkeeping.			X		Unit
Part 61 - EPA Regulations on National Emission Standards for Hazardous Air Pollutants						
Subpart A — General Provisions						
61.05	Prohibited Activities.		X			Facilty
61.09	Notification of Startup.		X			Facilty
61.10	Source Reporting and Request for Waiver of Compliance.		X			Facilty
61.11	Waiver of Compliance.		X			Facilty
61.12	Compliance with Standards and Maintenance Requirements.		X			Facilty
61.13	Emission Tests and Waiver of Emission Tests.		X			Facilty
61.14	Monitoring Requirements.		X			Facilty

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
61.19	Circumvention.		X			Facilty
Subpart M — National Emission Standards for Asbestos			X			Facility
Appendix C to Part 61 — Quality Assurance Procedures			X			Facility
Part 63 - EPA Regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories						
Subpart A — General Provisions						
63.4	Prohibited Activities and Circumvention.			X		Unit
63.6	Compliance with Standards and Maintenance Requirements.			X		Unit
63.7	Performance Testing Requirements.			X		Unit
63.8	Monitoring Requirements.			X		Unit
63.9	Notification Requirements.			X		Unit
63.10	Reporting and Recordkeeping Requirements.			X		Unit
63.11	Control Device Requirements.			X		Unit
Subpart Q — National Emission Standards for Industrial Process Cooling Towers						
63.402	Standard.			X		Unit
63.403	Compliance Dates.			X		Unit
63.404	Compliance Demonstrations.			X		Unit
63.405	Notification Requirements.			X		Unit
63.406	Recordkeeping and Reporting Requirements.			X		Unit
Subpart T — National Emission Standards for Halogenated Solvent Cleaning						
63.462	Batch Cold Cleaning Machine Standards.		X			Facilty
63.463	Batch Vapor and In-Line Cleaning Machine Standards.		X			Facilty
63.464	Alternative Standards.		X			Facilty

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
63.465	Test Methods.		X			Facilty
63.466	Monitoring Procedures.		X			Facilty
63.467	Recordkeeping Requirements.		X			Facilty
63.468	Reporting Requirements.		X			Facilty
Part 72 - EPA Acid Rain Program Permits						
Subpart A — General Provisions						
72.7	New Units Exemption.	001, 002, 003, 006, 007	X			Unit
72.8	Retired Units Exemption.	001, 002, 003, 006, 007	X			Unit
72.9	Standard Requirements.	001, 002, 003, 006, 007	X			Unit
Subpart B — Designated Representative						
72.20	Authorization and Responsibilities of the Designated Representative	001, 002, 003, 006, 007	X			Unit
72.21	Submissions.	001, 002, 003, 006, 007	X			Unit
72.22	Alternate Designated Representative.	001, 002, 003, 006, 007	X			Unit
72.23	Changing the Designated Representative, Alternate Designated Representative; Changes in the Owners and Operators.	001, 002, 003, 006, 007	X			Unit
Subpart C — Acid Rain Applications						
72.30	Requirements to Apply.	001, 002, 003, 006, 007	X			Unit
72.32	Permit Applications Shield and Binding Effect of Permit Application.	001, 002, 003, 006, 007	X			Unit

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
72.33	Identification of Dispatch System.	001, 002, 003, 006, 007	X			Unit
Subpart D — Acid Rain Compliance Plan and Compliance Options						
72.40	General.	001, 002, 003, 006, 007	X			Unit
72.41	Phase I Substitution Plans.	001, 002, 003, 006, 007	X			Unit
72.42	Phase I Extension Plans.	001, 002, 003, 006, 007	X			Unit
72.43	Phase I Reduced Utilization Plans.	001, 002, 003, 006, 007	X			Unit
72.44	Phase II Repowering Extensions.	001, 002, 003, 006, 007	X			Unit
Subpart E — Acid Rain Permit Contents						
72.51	Permit Shield.	001, 002, 003, 006, 007	X			Unit
Subpart I - Compliance Certification						
72.90	Annual Compliance Certification Report.	001, 002, 003, 006, 007	X			Unit
72.91	Phase I Unit Adjusted Utilization.	001, 002, 003, 006, 007	X			Unit
72.92	Phase I Unit Allowance Surrender.	001, 002, 003, 006, 007	X			Unit
72.93	Units with Phase I Extension Plans.	001, 002, 003, 006, 007	X			Unit
72.94	Units with Repowering Extension Plans.	001, 002, 003, 006, 007	X			Unit

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
Part 73 - EPA Acid Rain Program Sulfur Dioxide Allowance System						
Subpart C — Allowance Tracking System						
73.35	Compliance.	001, 002, 003, 006, 007	X			Unit
Part 75 - EPA Acid Rain Program For Continuous Emission Monitoring						
Subpart A — General						
75.4	Compliance Dates.	001, 002, 003, 006, 007	X			Unit
75.5	Prohibitions.	001, 002, 003, 006, 007	X			Unit
Subpart B — Monitoring Provisions						
75.10	General Operating Requirements.	001, 002, 003, 006, 007	X			Unit
75.11	Specific Provisions for Monitoring SO_2 Emissions (SO_2 and Flow Monitors).	001, 002, 003, 006, 007	X			Unit
75.12	Specific Provisions for Monitoring NO_x Emissions (NO_x and Diluent Gas Monitors).	001, 002, 003, 006, 007	X			Unit
75.13	Specific Provisions for Monitoring CO_2 Emissions.	001, 002, 003, 006, 007	X			Unit
75.14	Specific Provisions for Monitoring Opacity.	001, 002, 003, 006, 007	X			Unit
75.15	Specific Provisions for Monitoring SO_2 Emissions Removal by Qualifying Phase I Technology.	001, 002, 003, 006, 007	X			Unit
75.16	Specific Provisions for Monitoring Emissions from Common, By-Pass, and Multiple Stacks for SO_2 Emissions and Heat Input Determinations.	001, 002, 003, 006, 007	X			Unit

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
75.17	Specific Provisions for Monitoring Emissions from Common, By-Pass, and Multiple Stacks for NO_x Emission Rate.	001, 002, 003, 006, 007	X			Unit
75.18	Specific Provisions for Monitoring Emissions from Common, By-Pass, and Multiple Stacks for Opacity.	001, 002, 003, 006, 007	X			Unit
Subpart C — Operation and Maintenance Requirements						
75.20	Certification and Recertification Procedures.	001, 002, 003, 006, 007	X			Unit
75.21	Quality Assurance and Quality Control Requirements.	001, 002, 003, 006, 007	X			Unit
75.22	Reference Test Methods.	001, 002, 003, 006, 007	X			Unit
75.24	Out-of-Control Periods.	001, 002, 003, 006, 007	X			Unit
Subpart D — Missing Data Substitution Procedures						
75.30	General Provisions.	001, 002, 003, 006, 007	X			Unit
75.31	Initial Missing Data Procedures.	001, 002, 003, 006, 007	X			Unit
75.32	Determination of Monitor Data Availability for Standard Missing Data Procedures.	001, 002, 003, 006, 007	X			Unit
75.33	Standard Missing Data Procedures.	001, 002, 003, 006, 007	X			Unit
75.34	Units with Add-On Emission Controls.	001, 002, 003, 006, 007	X			Unit
Subpart E — Alternative Monitoring Systems						
75.40	General Demonstration Requirements.	001, 002, 003, 006, 007	X			Unit

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
75.41	Precision Criteria.	001, 002, 003, 006, 007	X			Unit
75.42	Reliability Criteria.	001, 002, 003, 006, 007	X			Unit
75.43	Accessibility Criteria.	001, 002, 003, 006, 007	X			Unit
75.44	Timeliness Criteria.	001, 002, 003, 006, 007	X			Unit
75.45	Daily Quality Assurance Criteria.	001, 002, 003, 006, 007	X			Unit
75.46	Missing Data Substitution Criteria.	001, 002, 003, 006, 007	X			Unit
75.47	Criteria for a Class of Affected Units.	001, 002, 003, 006, 007	X			Unit
75.48	Petition for an Alternative Monitoring System.	001, 002, 003, 006, 007	X			Unit
Subpart F — Recordkeeping Requirements						
75.50	General Recordkeeping Provisions.	001, 002, 003, 006, 007	X			Unit
75.51	General Recordkeeping Provisions for Specific Situations.	001, 002, 003, 006, 007	X			Unit
75.52	Certification, Quality Assurance, and Quality Control Record Provisions.	001, 002, 003, 006, 007	X			Unit
75.53	Monitoring Plan.	001, 002, 003, 006, 007	X			Unit
Subpart G — Reporting Requirements						

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
75.60	General Provisions.	001, 002, 003, 006, 007	X			Unit
75.61	Notification of Certification and Recertification Test Dates.	001, 002, 003, 006, 007	X			Unit
75.62	Monitoring Plan.	001, 002, 003, 006, 007	X			Unit
75.63	Certification or Recertification Applications.	001, 002, 003, 006, 007	X			Unit
75.64	Quarterly Reports.	001, 002, 003, 006, 007	X			Unit
75.65	Opacity Reports.	001, 002, 003, 006, 007	X			Unit
Appendix A to Part 75 — Specifications and Test Procedures		001, 002, 003, 006, 007	X			Unit
Appendix B to Part 75 — Quality Assurance and Quality Control Procedures		001, 002, 003, 006, 007	X			Unit
Appendix C to Part 75 — Missing Data Statistical Estimation Procedures		001, 002, 003, 006, 007	X			Unit
Appendix D to Part 75 — Optional SO_2 Emissions Data Protocol for Gas-Fired Units and Oil-Fired Units		001, 002, 003, 006, 007	X			Unit
Appendix E to Part 75 — Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units		001, 002, 003, 006, 007	X			Unit
EPA Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program						
76.5	NO_x Emission Limitations for Group 1 Boilers.	001, 002, 003, 006, 007	X			Unit

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
76.8	Early Election for Group 1, Phase II Boilers.	001, 002, 003, 006, 007	X			Unit
76.9	Permit Applications and Compliance Plans.	001, 002, 003, 006, 007	X			Unit
76.10	Alternative Emission Limitations.	001, 002, 003, 006, 007	X			Unit
76.11	Emissions Averaging.	001, 002, 003, 006, 007	X			Unit
76.12	Phase I NO_x Compliance Extensions.	001, 002, 003, 006, 007	X			Unit
76.14	Monitoring, Recordkeeping, and Reporting.	001, 002, 003, 006, 007	X			Unit
76.15	Test Methods and Procedures.	001, 002, 003, 006, 007	X			Unit
EPA Part 82 - Protection Of Stratospheric Ozone						
Subpart B - Servicing of Motor Vehicle Air Conditioners						
82.34	Prohibitions.			X		Facility
82.36	Approved refrigerant recycling equipment.			X		Facility
82.38	Approved independent standards testing organizations.			X		Facility
82.40	Technician training and certification.			X		Facility
82.42	Certification, recordkeeping and public notification requirements.			X		Facility
Subpart F - Recycling and Emissions Reduction						
82.154	Prohibitions.		X			Facility
82.156	Required practice.		X			Facility
82.158	Standards for recycling and recovery equipment.		X			Facility

EPA Rule	EPA Title	Facility Emission Unit Identification Number(s)	Applicable Requirement		Comments/Discussion	Potential Applicability
			Yes	No/NA		
82.160	Approved equipment testing organizations.		X			Facility
82.161	Technician certification.		X			Facility
82.162	Certification by owners of recovery and recycling equipment.		X			Facility
82.164	Reclaimer certification.		X			Facility
82.166(k)	Reporting and recordkeeping requirements for owners/operators.		X			Facility

ENSR
Consulting • Engineering • Remediation

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FAX(904) 385-5457

May 8, 1996

Mr. Bob Hicks
Orlando Utilities Commission
500 South Orange Avenue
Orlando, FL 32802

REVISED

Subject - Regulatory Applicability for Indian River Plant
ENSR Project No. 9420-030 Orlando P.O. Ref. C 96802 E

Dear Bob:

ENSR is providing a **Revised Determination of Regulatory Applicable** for the Indian River Plant. The determination is based upon the following information:

UNIT	INSTAL	MW	MMBTU/HR	MMBTU/HR	BACT	NSPS
BOILER 1	1959	87	832.2 OIL	865.5 NG	NO	NO
BOILER 2	1968	192	2016.5 OIL	2248.7 NG	NO	NO
BOILER 3	1970	328	3048.8 OIL	3208.5 NG	NO	NO
CT A & B	1990	35	445 OIL	445 NG	YES	SUBPART GG
CT C & D	1991	129	1346 OIL	1354 NG	YES	SUBPART GG
LIME SILO	1992	-	WATER	TREAT	NO	NO

Facility Regulatory Applicability - the Indian River Plant as a whole is subject to the "Title V Core List of Rules dated 3-25-96".except 40 CFR 61 (NESHAP), 40 CFR 82 (ozone, etc.), 62-296.400 (incinerators) and 62-281 (motor vehicle a/c)

40 CFR 60.1 Applicability
40 CFR 60.2 Definitions
40 CFR 60.3 Units and Abbreviations
40 CFR 60.4 Address
40 CFR 60.5 Determination of Construction or Modification
40 CFR 60.6 Review of Plans
40 CFR 60.7 Notification and Recordkeeping
40 CFR 60.8 Performance Tests
40 CFR 60.9 Availability of Information
40 CFR 60.10 State Authority
40 CFR 60.11 Compliance with Standards and Maintenance Requirements
40 CFR 60.12 Circumvention
40 CFR 60.13 Monitoring Requirements
40 CFR 60.14 Modification
40 CFR 60.15 Reconstruction
40 CFR 60.16 Priority List
40 CFR 60.17 Incorporation by Reference

ENSR

62-210.700 Excess Emissions
62-212.300 General Preconstruction Review (future major modifications)
62-212.400 PSD (future major modifications)
62-213-415 Trading of Emissions within a Source
62-213.450 EPA and Affected States Review
62-296.600(5) Record Keeping/Reporting (Permit Condition)
62-297.100 Monitoring Purpose/Scope
62-297.310 General Test Requirements
62-297.401 Compliance Test Methods
62-297.440 Supplementary Test (ASTM, EPA Reports, etc.)
62-297.620 Exceptions and Approval of Alternate Procedures

Emission Unit Regulatory Applicability - Boilers 1, 2 and 3 are subject to the following additional state and federal regulations:

62-213.413 Fast Track Permitting for Acid Rain Sources
62-214 Requirements for Sources Subject to Acid Rain Program
62-296.405 Fossil Fuel Steam Generators >250 MMBtu/hr heat input

Emission Unit Regulatory Applicability - Combustion Turbines A, B, C and D are subject to the following additional state and federal regulations:

Subpart GG Standards for Performance for Stationary Gas Turbines
62-214 Requirements for Sources Subject to Acid Rain Program (CT C & D only)

Emission Unit Regulatory Applicability - LIME SILO is subject to the following additional state and federal regulations:

62-296.320 (2) No Objectionable Odors
62-296.414 Concrete Batching Plants (permit)

Please review this list to assure that I have included only the regulations which are appropriate, have not omitted any applicable regulations and include any comments on the above determination by 4/26/96.

Sincerely,

Preston Lewis, P.E.
Senior Project Manager

cc. Barry Andrews and Keith Field

APPENDIX L

EMISSIONS INVENTORY

SUPPORTING CALCULATIONS

OUC - Indian River

$MMBtu := 1000000 \cdot BTU$
$Btu := BTU$
$bbl := 42 \cdot gal$
$MMscf := 1000000 \cdot scf$

$cfm := \frac{ft^3}{min}$ $gr := \frac{lb}{7000}$ $tpy := \frac{ton}{yr}$ $scf := ft^3$

$ppm := \frac{1}{1000000}$ $tph := \frac{ton}{hr}$

OUC - Indian River

Boiler 1, Emission Unit 01

Permit Restrictions:

Btu Oil: 832.2 MMBtu/hr
Btu Gas: 865.5 MMBtu/hr
Operating Hours: 8400 hr/yr
Up to 1% of total Btu input may be from On-spec Used Oil

PM Steady state: 0.1 lb/MMBtu
PM Soot Blowing: 0.3 lb/MMBtu for < 3 hrs
SO2: 2.75 lb/MMBtu

$$OilBtu := 6.0 \cdot \frac{MMBtu}{bbl}$$

$$GasBtu := 1000 \cdot \frac{Btu}{scf}$$

PM Emissions (from permit)

Max Hourly

$$PM := 0.3 \cdot \frac{lb}{MMBtu} \cdot 832.2 \cdot \frac{MMBtu}{hr} \qquad PM = 249.7 \cdot \frac{lb}{hr}$$

Potential Annual

$$PM := 0.1 \cdot \frac{lb}{MMBtu} \cdot 832.2 \cdot \frac{MMBtu}{hr} \cdot 8400 \cdot \frac{hr}{yr} \qquad PM = 349.5 \cdot tpy$$

PM10 Emissions

AP42, 5th ed., indicates while burning residual oil, PM10 makes up about 71% of uncontrolled PM emissions

Max Hourly

$$PM10 := 0.71 \cdot 0.3 \cdot \frac{lb}{MMBtu} \cdot 832.2 \cdot \frac{MMBtu}{hr} \qquad PM10 = 177.3 \cdot \frac{lb}{hr}$$

Potential Annual

$$PM10 := 0.71 \cdot 0.1 \cdot \frac{lb}{MMBtu} \cdot 832.2 \cdot \frac{MMBtu}{hr} \cdot 8400 \cdot \frac{hr}{yr} \qquad PM10 = 248.2 \cdot tpy$$

OUC - Indian River

SO2 Emissions (from permit)

Max Hourly

$SO2 := 2.75 \cdot \frac{lb}{MMBtu} \cdot 832.2 \cdot \frac{MMBtu}{hr}$ $SO2 = 2288.5 \cdot \frac{lb}{hr}$

Potential Annual

$SO2 := 2.75 \cdot \frac{lb}{MMBtu} \cdot 832.2 \cdot \frac{MMBtu}{hr} \cdot 8400 \cdot \frac{hr}{yr}$ $SO2 = 9611.9 \cdot tpy$

NOx Emissions (AP42, 5th ed.)

Max Hourly

$GasHour := 865.5 \cdot \frac{MMBtu}{hr} \cdot \frac{1}{GasBtu}$ $GasHour = 8.655 \cdot 10^5 \cdot \frac{scf}{hr}$

$NOx := 275 \cdot \frac{lb}{MMscf} \cdot GasHour$ $NOx = 238.012 \cdot \frac{lb}{hr}$ (Tangential Fire)

$OilHour := 832.2 \cdot \frac{MMBtu}{hr} \cdot \frac{1}{OilBtu}$ $OilHour = 5825.4 \cdot \frac{gal}{hr}$

$NOx := 67 \cdot \frac{lb}{1000 \cdot gal} \cdot OilHour$ $NOx = 390.302 \cdot \frac{lb}{hr}$ Higher Potential

Potential Annual

$8400 \cdot \frac{hr}{yr} \cdot NOx = 1639.267 \cdot tpy$

CO Emissions (AP42, 5th ed.)

Max Hourly

$CO := 5 \cdot \frac{lb}{1000 \cdot gal} \cdot OilHour$ $CO = 29.127 \cdot \frac{lb}{hr}$

$CO := 40 \cdot \frac{lb}{MMscf} \cdot GasHour$ $CO = 34.62 \cdot \frac{lb}{hr}$ Higher Potential

Potential Annual

$8400 \cdot \frac{hr}{yr} \cdot CO = 145.404 \cdot tpy$

OUC - Indian River

Non-Methane TOC Emissions (AP-42, 5th ed.)

Max Hourly

$$TOC := 0.83 \cdot 1.7 \cdot \frac{lb}{MMscf} \cdot GasHour \qquad TOC = 1.221 \cdot \frac{lb}{hr}$$

$$TOC := 0.76 \cdot \frac{lb}{1000 \cdot gal} \cdot OilHour \qquad TOC = 4.427 \cdot \frac{lb}{hr}$$ Higher Potential

Potential Annual

$$TOC \cdot 8400 \cdot \frac{hr}{yr} = 18.595 \cdot tpy$$

Formaldehyde Emissions (AP42, 5th ed.), range 161 to 405 lb/10E12 Btu

Max Hourly

$$HCOH := 405 \cdot \frac{lb}{10^{12} \cdot Btu} \cdot 832.2 \cdot \frac{MMBtu}{hr} \qquad HCOH = 0.337 \cdot \frac{lb}{hr}$$

Potential Annual

$$HCOH \cdot 8400 \cdot \frac{hr}{yr} = 1.416 \cdot tpy$$

OUC - Indian River

Trace Elements (AP42, 5th ed.), using high end of range

	Max Hourly	Annual Potential
Sb := 46·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	Sb = 0.038·lb·hr^-1	Sb·8400·hr·yr^-1 = 0.161·tpy
As := 114·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	As = 0.095·lb·hr^-1	As·8400·hr·yr^-1 = 0.398·tpy
Be := 4.2·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	Be = 0.003·lb·hr^-1	Be·8400·hr·yr^-1 = 0.015·tpy
Cd := 211·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	Cd = 0.176·lb·hr^-1	Cd·8400·hr·yr^-1 = 0.737·tpy
Cr := 128·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	Cr = 0.107·lb·hr^-1	Cr·8400·hr·yr^-1 = 0.447·tpy
Co := 121·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	Co = 0.101·lb·hr^-1	Co·8400·hr·yr^-1 = 0.423·tpy
Pb := 194·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	Pb = 0.161·lb·hr^-1	Pb·8400·hr·yr^-1 = 0.678·tpy
Mn := 74·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	Mn = 0.062·lb·hr^-1	Mn·8400·hr·yr^-1 = 0.259·tpy
Hg := 32·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	Hg = 0.027·lb·hr^-1	Hg·8400·hr·yr^-1 = 0.112·tpy
Ni := 2330·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	Ni = 1.939·lb·hr^-1	Ni·8400·hr·yr^-1 = 8.144·tpy
Se := 38·lb·10^-12·Btu^-1·832.2·MMBtu·hr^-1	Se = 0.032·lb·hr^-1	Se·8400·hr·yr^-1 = 0.133·tpy

Contribution of metals from Used Oil, per correspondence from OUC 5/23/95

$Metals := 100 \cdot ppm \cdot 1 \cdot \%\cdot OilHour \cdot 8 \cdot \frac{lb}{gal}$ $Metals = 0.047 \cdot \frac{lb}{hr}$ $Metals \cdot 8400 \cdot \frac{hr}{yr} = 0.196 \cdot tpy$

Assume Metals could be primarily either Pb or Ni, add to each of Pb and Ni from above:

Pb := Pb + Metals	Pb = 0.208·lb·hr^-1	Pb·8400·hr·yr^-1 = 0.874·tpy
Ni := Ni + Metals	Ni = 1.986·lb·hr^-1	Ni·8400·hr·yr^-1 = 8.34·tpy

Assume Maximum Cl in used oil = 1000 ppm

$HCl := 66 \cdot 1 \cdot \%\cdot 1000 \cdot ppm \cdot 8 \cdot \frac{lb}{gal} \cdot OilHour$ $HCl = 30.758 \cdot \frac{lb}{hr}$ $HCl \cdot 8400 \cdot \frac{hr}{yr} = 129.184 \cdot tpy$

The remaining pollutants in the AP-42 used oil table (1.11-4,5) are assigned an emission factor rating of "D", which is probably not well represented by the used oil burned by OUC, since that used oil is specifically generated by OUC. At only 1% of the total Btu input, the metals output should not be significantly affected. This is illustrated using As as an example. Also, the AP42 Used Oil tables only provide information for SMALL boilers and space heaters.

$AsU := 0.11 \cdot \frac{lb}{1000 \cdot gal} \cdot 1 \cdot \%\cdot OilHour$ $AsU = 0.006 \cdot \frac{lb}{hr}$ $As = 0.095 \cdot \frac{lb}{hr}$

OUC - Indian River

Boiler 2, Emission Unit 02

Permit Restrictions:

Btu Oil: 2016.5 MMBtu/hr
Btu Gas: 2248.7 MMBtu/hr
Operating Hours: 8400 hr/yr
Up to 1% of total Btu Input may be from On-spec Used Oil

PM Steady state: 0.1 lb/MMBtu
PM Soot Blowing: 0.3 lb/MMBtu for < 3 hrs
SO2: 2.75 lb/MMBtu

$$OilBtu := 6.0 \cdot \frac{MMBtu}{bbl}$$

$$GasBtu := 1000 \cdot \frac{Btu}{scf}$$

PM Emissions (from permit)

Max Hourly

$$PM := 0.3 \cdot \frac{lb}{MMBtu} \cdot 2016.5 \cdot \frac{MMBtu}{hr} \qquad PM = 604.9 \cdot \frac{lb}{hr}$$

Potential Annual

$$PM := 0.1 \cdot \frac{lb}{MMBtu} \cdot 2016.5 \cdot \frac{MMBtu}{hr} \cdot 8400 \cdot \frac{hr}{yr} \qquad PM = 846.9 \cdot tpy$$

PM10 Emissions

AP42, 5th ed., indicates while burning residual oil, PM10 makes up about 71% of uncontrolled PM emissions

Max Hourly

$$PM10 := 0.71 \cdot 0.3 \cdot \frac{lb}{MMBtu} \cdot 2016.5 \cdot \frac{MMBtu}{hr} \qquad PM10 = 429.5 \cdot \frac{lb}{hr}$$

Potential Annual

$$PM10 := 0.71 \cdot 0.1 \cdot \frac{lb}{MMBtu} \cdot 2016.5 \cdot \frac{MMBtu}{hr} \cdot 8400 \cdot \frac{hr}{yr} \qquad PM10 = 601.3 \cdot tpy$$

OUC - Indian River

SO2 Emissions (from permit)

Max Hourly

$SO2 := 2.75 \cdot \frac{lb}{MMBtu} \cdot 2016.5 \cdot \frac{MMBtu}{hr}$ $SO2 = 5545.4 \cdot \frac{lb}{hr}$

Potential Annual

$SO2 := 2.75 \cdot \frac{lb}{MMBtu} \cdot 2016.5 \cdot \frac{MMBtu}{hr} \cdot 8400 \cdot \frac{hr}{yr}$ $SO2 = 23290.6 \cdot tpy$

NOx Emissions (AP42, 5th ed.)

Max Hourly

$GasHour := 2248.7 \cdot \frac{MMBtu}{hr} \cdot \frac{1}{GasBtu}$ $GasHour = 2.249 \cdot 10^6 \cdot \frac{scf}{hr}$

$NOx := 275 \cdot \frac{lb}{MMscf} \cdot GasHour$ $NOx = 618.392 \cdot \frac{lb}{hr}$ (Tangential Fire)

$OilHour := 2016.5 \cdot \frac{MMBtu}{hr} \cdot \frac{1}{OilBtu}$ $OilHour = 14115.5 \cdot \frac{gal}{hr}$

$NOx := 67 \cdot \frac{lb}{1000 \cdot gal} \cdot OilHour$ $NOx = 945.738 \cdot \frac{lb}{hr}$ Higher Potential

Potential Annual

$8400 \cdot \frac{hr}{yr} \cdot NOx = 3972.101 \cdot tpy$

CO Emissions (AP42, 5th ed.)

Max Hourly

$CO := 5 \cdot \frac{lb}{1000 \cdot gal} \cdot OilHour$ $CO = 70.578 \cdot \frac{lb}{hr}$

$CO := 40 \cdot \frac{lb}{MMscf} \cdot GasHour$ $CO = 89.948 \cdot \frac{lb}{hr}$ Higher Potential

Potential Annual

$8400 \cdot \frac{hr}{yr} \cdot CO = 377.782 \cdot tpy$

OUC - Indian River

Non-Methane TOC Emissions (AP-42, 5th ed.)

Max Hourly

$$TOC := 0.83 \cdot 1.7 \cdot \frac{lb}{MMscf} \cdot GasHour \qquad TOC = 3.173 \cdot \frac{lb}{hr}$$

$$TOC := 0.76 \cdot \frac{lb}{1000 \cdot gal} \cdot OilHour \qquad TOC = 10.728 \cdot \frac{lb}{hr}$$ Higher Potential

Potential Annual

$$TOC \cdot 8400 \cdot \frac{hr}{yr} = 45.057 \cdot tpy$$

Formaldehyde Emissions (AP42, 5th ed.), range 181 to 405 lb/10E12 Btu

Max Hourly

$$HCOH := 405 \cdot \frac{lb}{10^{12} \cdot Btu} \cdot 2016.5 \cdot \frac{MMBtu}{hr} \qquad HCOH = 0.817 \cdot \frac{lb}{hr}$$

Potential Annual

$$HCOH \cdot 8400 \cdot \frac{hr}{yr} = 3.43 \cdot tpy$$

OUC - Indian River

Trace Elements (AP42, 5th ed.), using high end of range

	Max Hourly	Annual Potential
$Sb := 46 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$Sb = 0.093 \cdot lb \cdot hr^{-1}$	$Sb \cdot 8400 \cdot hr \cdot yr^{-1} = 0.39 \cdot tpy$
$As := 114 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$As = 0.23 \cdot lb \cdot hr^{-1}$	$As \cdot 8400 \cdot hr \cdot yr^{-1} = 0.965 \cdot tpy$
$Be := 4.2 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$Be = 0.008 \cdot lb \cdot hr^{-1}$	$Be \cdot 8400 \cdot hr \cdot yr^{-1} = 0.036 \cdot tpy$
$Cd := 211 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$Cd = 0.425 \cdot lb \cdot hr^{-1}$	$Cd \cdot 8400 \cdot hr \cdot yr^{-1} = 1.787 \cdot tpy$
$Cr := 128 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$Cr = 0.258 \cdot lb \cdot hr^{-1}$	$Cr \cdot 8400 \cdot hr \cdot yr^{-1} = 1.084 \cdot tpy$
$Co := 121 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$Co = 0.244 \cdot lb \cdot hr^{-1}$	$Co \cdot 8400 \cdot hr \cdot yr^{-1} = 1.025 \cdot tpy$
$Pb := 194 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$Pb = 0.391 \cdot lb \cdot hr^{-1}$	$Pb \cdot 8400 \cdot hr \cdot yr^{-1} = 1.643 \cdot tpy$
$Mn := 74 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$Mn = 0.149 \cdot lb \cdot hr^{-1}$	$Mn \cdot 8400 \cdot hr \cdot yr^{-1} = 0.627 \cdot tpy$
$Hg := 32 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$Hg = 0.065 \cdot lb \cdot hr^{-1}$	$Hg \cdot 8400 \cdot hr \cdot yr^{-1} = 0.271 \cdot tpy$
$Ni := 2330 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$Ni = 4.698 \cdot lb \cdot hr^{-1}$	$Ni \cdot 8400 \cdot hr \cdot yr^{-1} = 19.733 \cdot tpy$
$Se := 38 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 2016.5 \cdot MMBtu \cdot hr^{-1}$	$Se = 0.077 \cdot lb \cdot hr^{-1}$	$Se \cdot 8400 \cdot hr \cdot yr^{-1} = 0.322 \cdot tpy$

Contribution of metals from Used Oil, per correspondence from OUC 5/23/95

$Metals := 100 \cdot ppm \cdot 1 \cdot \% \cdot OilHour \cdot 8 \cdot \frac{lb}{gal}$ $\quad Metals = 0.113 \cdot \frac{lb}{hr}$ $\quad Metals \cdot 8400 \cdot \frac{hr}{yr} = 0.474 \cdot tpy$

Assume Metals could be primarily either Pb or Ni, add to each of Pb and Ni from above:

$Pb := Pb + Metals$	$Pb = 0.504 \cdot lb \cdot hr^{-1}$	$Pb \cdot 8400 \cdot hr \cdot yr^{-1} = 2.117 \cdot tpy$
$Ni := Ni + Metals$	$Ni = 4.811 \cdot lb \cdot hr^{-1}$	$Ni \cdot 8400 \cdot hr \cdot yr^{-1} = 20.208 \cdot tpy$

Assume Maximum Cl in used oil = 1000 ppm

$HCl := 66 \cdot 1 \cdot \% \cdot 1000 \cdot ppm \cdot 8 \cdot \frac{lb}{gal} \cdot OilHour$ $\quad HCl = 74.53 \cdot \frac{lb}{hr}$ $\quad HCl \cdot 8400 \cdot \frac{hr}{yr} = 313.025 \cdot tpy$

The remaining pollutants in the AP-42 used oil table (1.11-4,5) are assigned an emission factor rating of "D", which is probably not well represented by the used oil burned by OUC, since that used oil is specifically generated by OUC. At only 1% of the total Btu input, the metals output should not be significantly affected. This is illustrated using As as an example. Also, the AP42 Used Oil tables only provide information for SMALL boilers and space heaters.

$AsU := 0.11 \cdot \frac{lb}{1000 \cdot gal} \cdot 1 \cdot \% \cdot OilHour$ $\quad AsU = 0.016 \cdot \frac{lb}{hr}$ $\quad As = 0.23 \cdot \frac{lb}{hr}$

OUC - Indian River

Boiler 3, Emission Unit 03

Permit Restrictions:

Btu Oil: 3048.8 MMBtu/hr
Btu Gas: 3208.5 MMBtu/hr
Operating Hours: 8400 hr/yr
Up to 1% of total Btu input may be from On-spec Used Oil

PM Steady state: 0.1 lb/MMBtu
PM Soot Blowing: 0.3 lb/MMBtu for < 3 hrs
SO2: 2.75 lb/MMBtu

$$OilBtu := 6.0 \cdot \frac{MMBtu}{bbl}$$

$$GasBtu := 1000 \cdot \frac{Btu}{scf}$$

PM Emissions (from permit)

Max Hourly

$$PM := 0.3 \cdot \frac{lb}{MMBtu} \cdot 3048.8 \cdot \frac{MMBtu}{hr} \qquad PM = 914.6 \cdot \frac{lb}{hr}$$

Potential Annual

$$PM := 0.1 \cdot \frac{lb}{MMBtu} \cdot 3048.8 \cdot \frac{MMBtu}{hr} \cdot 8400 \cdot \frac{hr}{yr} \qquad PM = 1.3 \cdot 10^3 \cdot tpy$$

PM10 Emissions

AP42, 5th ed., indicates while burning residual oil, PM10 makes up about 71% of uncontrolled PM emissions

Max Hourly

$$PM10 := 0.71 \cdot 0.3 \cdot \frac{lb}{MMBtu} \cdot 3048.8 \cdot \frac{MMBtu}{hr} \qquad PM10 = 649.4 \cdot \frac{lb}{hr}$$

Potential Annual

$$PM10 := 0.71 \cdot 0.1 \cdot \frac{lb}{MMBtu} \cdot 3048.8 \cdot \frac{MMBtu}{hr} \cdot 8400 \cdot \frac{hr}{yr} \qquad PM10 = 909.2 \cdot tpy$$

OUC - Indian River

SO2 Emissions (from permit)

Max Hourly

$SO2 := 2.75 \cdot \frac{lb}{MMBtu} \cdot 3048.8 \cdot \frac{MMBtu}{hr}$ $SO2 = 8384.2 \cdot \frac{lb}{hr}$

Potential Annual

$SO2 := 2.75 \cdot \frac{lb}{MMBtu} \cdot 3048.8 \cdot \frac{MMBtu}{hr} \cdot 8400 \cdot \frac{hr}{yr}$ $SO2 = 35213.6 \cdot tpy$

NOx Emissions (AP42, 5th ed.)

Max Hourly

$GasHour := 3208.5 \cdot \frac{MMBtu}{hr} \cdot \frac{1}{GasBtu}$ $GasHour = 3.209 \cdot 10^6 \cdot \frac{scf}{hr}$

$NOx := 275 \cdot \frac{lb}{MMscf} \cdot GasHour$ $NOx = 882.337 \cdot \frac{lb}{hr}$ (Tangential Fire)

$OilHour := 3048.8 \cdot \frac{MMBtu}{hr} \cdot \frac{1}{OilBtu}$ $OilHour = 21341.6 \cdot \frac{gal}{hr}$

$NOx := 67 \cdot \frac{lb}{1000 \cdot gal} \cdot OilHour$ $NOx = 1429.887 \cdot \frac{lb}{hr}$ Higher Potential

Potential Annual

$8400 \cdot \frac{hr}{yr} \cdot NOx = 6005.525 \cdot tpy$

CO Emissions (AP42, 5th ed.)

Max Hourly

$CO := 5 \cdot \frac{lb}{1000 \cdot gal} \cdot OilHour$ $CO = 106.708 \cdot \frac{lb}{hr}$

$CO := 40 \cdot \frac{lb}{MMscf} \cdot GasHour$ $CO = 128.34 \cdot \frac{lb}{hr}$ Higher Potential

Potential Annual

$8400 \cdot \frac{hr}{yr} \cdot CO = 539.028 \cdot tpy$

OUC - Indian River

Non-Methane TOC Emissions (AP-42, 5th ed.)

Max Hourly

$$TOC := 0.83 \cdot 1.7 \cdot \frac{lb}{MMscf} \cdot GasHour \qquad TOC = 4.527 \cdot \frac{lb}{hr}$$

$$TOC := 0.76 \cdot \frac{lb}{1000 \cdot gal} \cdot OilHour \qquad TOC = 16.22 \cdot \frac{lb}{hr}$$ Higher Potential

Potential Annual

$$TOC \cdot 8400 \cdot \frac{hr}{yr} = 68.122 \cdot tpy$$

Formaldehyde Emissions (AP42, 5th ed.), range 161 to 405 lb/10E12 Btu

Max Hourly

$$HCOH := 405 \cdot \frac{lb}{10^{12} \cdot Btu} \cdot 3048.8 \cdot \frac{MMBtu}{hr} \qquad HCOH = 1.235 \cdot \frac{lb}{hr}$$

Potential Annual

$$HCOH \cdot 8400 \cdot \frac{hr}{yr} = 5.186 \cdot tpy$$

OUC - Indian River

Trace Elements (AP42, 5th ed.), using high end of range

	Max Hourly	Annual Potential
$Sb := 46 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$Sb = 0.14 \cdot lb \cdot hr^{-1}$	$Sb \cdot 8400 \cdot hr \cdot yr^{-1} = 0.589 \cdot tpy$
$As := 114 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$As = 0.348 \cdot lb \cdot hr^{-1}$	$As \cdot 8400 \cdot hr \cdot yr^{-1} = 1.46 \cdot tpy$
$Be := 4.2 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$Be = 0.013 \cdot lb \cdot hr^{-1}$	$Be \cdot 8400 \cdot hr \cdot yr^{-1} = 0.054 \cdot tpy$
$Cd := 211 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$Cd = 0.643 \cdot lb \cdot hr^{-1}$	$Cd \cdot 8400 \cdot hr \cdot yr^{-1} = 2.702 \cdot tpy$
$Cr := 128 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$Cr = 0.39 \cdot lb \cdot hr^{-1}$	$Cr \cdot 8400 \cdot hr \cdot yr^{-1} = 1.639 \cdot tpy$
$Co := 121 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$Co = 0.369 \cdot lb \cdot hr^{-1}$	$Co \cdot 8400 \cdot hr \cdot yr^{-1} = 1.549 \cdot tpy$
$Pb := 194 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$Pb = 0.591 \cdot lb \cdot hr^{-1}$	$Pb \cdot 8400 \cdot hr \cdot yr^{-1} = 2.484 \cdot tpy$
$Mn := 74 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$Mn = 0.226 \cdot lb \cdot hr^{-1}$	$Mn \cdot 8400 \cdot hr \cdot yr^{-1} = 0.948 \cdot tpy$
$Hg := 32 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$Hg = 0.098 \cdot lb \cdot hr^{-1}$	$Hg \cdot 8400 \cdot hr \cdot yr^{-1} = 0.41 \cdot tpy$
$Ni := 2330 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$Ni = 7.104 \cdot lb \cdot hr^{-1}$	$Ni \cdot 8400 \cdot hr \cdot yr^{-1} = 29.836 \cdot tpy$
$Se := 38 \cdot lb \cdot 10^{-12} \cdot Btu^{-1} \cdot 3048.8 \cdot MMBtu \cdot hr^{-1}$	$Se = 0.116 \cdot lb \cdot hr^{-1}$	$Se \cdot 8400 \cdot hr \cdot yr^{-1} = 0.487 \cdot tpy$

Contribution of metals from Used Oil, per correspondence from OUC 5/23/95

$Metals := 100 \cdot ppm \cdot 1 \cdot \% \cdot OilHour \cdot 8 \cdot \frac{lb}{gal}$ $\quad Metals = 0.171 \cdot \frac{lb}{hr}$ $\quad Metals \cdot 8400 \cdot \frac{hr}{yr} = 0.717 \cdot tpy$

Assume Metals could be primarily either Pb or Ni, add to each of Pb and Ni from above:

$Pb := Pb + Metals$	$Pb = 0.762 \cdot lb \cdot hr^{-1}$	$Pb \cdot 8400 \cdot hr \cdot yr^{-1} = 3.201 \cdot tpy$
$Ni := Ni + Metals$	$Ni = 7.274 \cdot lb \cdot hr^{-1}$	$Ni \cdot 8400 \cdot hr \cdot yr^{-1} = 30.553 \cdot tpy$

Assume Maximum Cl in used oil = 1000 ppm

$HCl := 66 \cdot 1 \cdot \% \cdot 1000 \cdot ppm \cdot 8 \cdot \frac{lb}{gal} \cdot OilHour$ $\quad HCl = 112.684 \cdot \frac{lb}{hr}$ $\quad HCl \cdot 8400 \cdot \frac{hr}{yr} = 473.271 \cdot tpy$

The remaining pollutants in the AP-42 used oil table (1.11-4,5) are assigned an emission factor rating of "D", which is probably not well represented by the used oil burned by OUC, since that used oil is specifically generated by OUC. At only 1% of the total Btu input, the metals output should not be significantly affected. This is illustrated using As as an example. Also, the AP42 Used Oil tables only provide information for SMALL boilers and space heaters.

$AsU := 0.11 \cdot \frac{lb}{1000 \cdot gal} \cdot 1 \cdot \% \cdot OilHour$ $\quad AsU = 0.023 \cdot \frac{lb}{hr}$ $\quad As = 0.348 \cdot \frac{lb}{hr}$

OUC - Indian River

Lime Storage Silo, Emission Unit 08, PM emissions = PM10 emissions:

Permit Restrictions:

Load Rate 10 tph
Load Time 2 hr/day (Would like to change to 4 hr/day)

Per OUC, Usage = 80 tpy; ACFM determined by truck, @35 lb/scf per lime company

$$SCFM := \frac{1 \cdot scf}{35 \cdot lb} \cdot \frac{2000 \cdot lb}{ton} \cdot \frac{10 \cdot ton}{hr} \cdot \frac{hr}{60 \cdot min} \qquad SCFM = 9.524 \cdot cfm$$

$$PM := 0.02 \cdot \frac{gr}{scf} \cdot SCFM \qquad PM = 0.002 \cdot \frac{lb}{hr}$$

$$LoadTime := 80 \cdot \frac{tpy}{10 \cdot tph} \qquad LoadTime = 8 \cdot \frac{hr}{yr} \qquad PM \cdot 8760 \cdot \frac{hr}{yr} = 0.007 \cdot tpy$$ Max Annual

$$PM \cdot 8 \cdot \frac{hr}{yr} = 6.531 \cdot 10^{-6} \cdot tpy$$ Estimated Annual

Potential Emissions:

$$PM \cdot 2 \cdot \frac{hr}{day} \cdot 365 \cdot \frac{day}{yr} = 0.001 \cdot tpy$$

This should be an insignificant source, with or without permit restrictions on operating hours.

OUC - Indian River

Combustion Turbines A, B (each), Emission Units 04 (A); 05 (B)

Permit Restrictions:

OP_HOURS := 8760·$\frac{hr}{yr}$ CT_Btu := 445·$\frac{MMBtu}{hr}$ @59 F

Gas:	NOx := 75.1·$\frac{lb}{hr}$	NOx·OP_HOURS = 328.9·tpy
Oil:	NOx := 118.3·$\frac{lb}{hr}$	NOx·OP_HOURS = 518.2·tpy
Gas:	SO2 := 0.34·$\frac{lb}{hr}$	SO2·OP_HOURS = 1.5·tpy
Oil:	SO2 := 142.7·$\frac{lb}{hr}$	SO2·OP_HOURS = 625·tpy

Although the following are "tabulated for PSD and inventory purposes" in the latest permit, but were max. allowables in previous edition of permit, based on BACT.

Gas:	CO := 10·$\frac{lb}{hr}$	CO·OP_HOURS = 43.8·tpy
Oil:	CO := 10.1·$\frac{lb}{hr}$	CO·OP_HOURS = 44.2·tpy
Gas:	PM := 2.5·$\frac{lb}{hr}$	PM·OP_HOURS = 10.9·tpy
Oil:	PM := 10·$\frac{lb}{hr}$	PM·OP_HOURS = 43.8·tpy
Gas:	PM10 := 2.5·$\frac{lb}{hr}$	PM10·OP_HOURS = 10.9·tpy
Oil:	PM10 := 10·$\frac{lb}{hr}$	PM10·OP_HOURS = 43.8·tpy
Gas:	VOC := 4·$\frac{lb}{hr}$	VOC·OP_HOURS = 17.5·tpy
Oil:	VOC := 4·$\frac{lb}{hr}$	VOC·OP_HOURS = 17.5·tpy
Oil:	H2SO4 := 10·$\frac{lb}{hr}$	H2SO4 := 44.0·tpy
Oil:	Be := 0.0001·$\frac{lb}{hr}$	Be := 0.0005·tpy

OUC - Indian River

From AP-42, 5th ed. (CTs A, B cont'd)

HCOH, only info is for SCR with water injection:

$HCOH := 0.0027 \cdot \frac{lb}{MMBtu} \cdot CT\_Btu$ $HCOH = 1.2 \cdot \frac{lb}{hr}$ $HCOH = 5.3 \cdot tpy$

Trace Elements, HAPS, not otherwise restricted by permit, distillate-oil fired:

$Sb := 2.2 \cdot 10^{-5} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$Sb = 0.01 \cdot lb \cdot hr^{-1}$	$Sb = 0.043 \cdot tpy$
$As := 4.9 \cdot 10^{-6} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$As = 0.002 \cdot lb \cdot hr^{-1}$	$As = 0.01 \cdot tpy$
$Cd := 4.2 \cdot 10^{-6} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$Cd = 0.002 \cdot lb \cdot hr^{-1}$	$Cd = 0.008 \cdot tpy$
$Cr := 4.7 \cdot 10^{-5} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$Cr = 0.021 \cdot lb \cdot hr^{-1}$	$Cr = 0.092 \cdot tpy$
$Co := 9.1 \cdot 10^{-6} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$Co = 0.004 \cdot lb \cdot hr^{-1}$	$Co = 0.018 \cdot tpy$
$Pb := 5.8 \cdot 10^{-5} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$Pb = 0.026 \cdot lb \cdot hr^{-1}$	$Pb = 0.113 \cdot tpy$
$Mn := 3.4 \cdot 10^{-4} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$Mn = 0.151 \cdot lb \cdot hr^{-1}$	$Mn = 0.663 \cdot tpy$
$Hg := 9.1 \cdot 10^{-7} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$Hg = 0 \cdot lb \cdot hr^{-1}$	$Hg = 0.002 \cdot tpy$
$Ni := 1.2 \cdot 10^{-3} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$Ni = 0.534 \cdot lb \cdot hr^{-1}$	$Ni = 2.34 \cdot tpy$
$P := 3.0 \cdot 10^{-4} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$P = 0.133 \cdot lb \cdot hr^{-1}$	$P = 0.585 \cdot tpy$
$Se := 5.3 \cdot 10^{-6} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu$	$Se = 0.002 \cdot lb \cdot hr^{-1}$	$Se = 0.01 \cdot tpy$

OUC - Indian River

Combustion Turbines C, D (each), Emission Units 06 (C); 07 (D)

Permit Restrictions:

OP_HOURS := 4380·$\frac{hr}{yr}$ CT_Btu_Gas := 1354·$\frac{MMBtu}{hr}$ CT_Btu_Oil := 1346·$\frac{MMBtu}{hr}$

MaxFO := 10282·$\frac{gal}{hr}$ OP_HOURS_FO := 2190·$\frac{hr}{yr}$

MaxFO·OP_HOURS_FO = 22517580·$\frac{gal}{yr}$

Worst case pollutants operating scenarios:

NOx := 801.8·tpy	(Gas & Oil)	506·tpy·2190·hr·yr^{-1} = 28.843·lb·hr^{-1}	(Oil)
SO2 := 954.1·tpy	(Gas & Oil)	953·tpy·2190·hr·yr^{-1} = 54.323·lb·hr^{-1}	(Oil)
PM := 246.8·tpy	(Gas & Oil)	237·tpy·2190·hr·yr^{-1} = 13.509·lb·hr^{-1}	(Oil)
PM10 := 246.8·tpy	(Gas & Oil)	237·tpy·2190·hr·yr^{-1} = 13.509·lb·hr^{-1}	(Oil)
CO := 315.5·tpy	(Gas & Oil)	159·tpy·2190·hr·yr^{-1} = 9.063·lb·hr^{-1}	(Oil)
VOC := 130.5·tpy	(Gas & Oil)	112·tpy·2190·hr·yr^{-1} = 6.384·lb·hr^{-1}	(Oil)
H2SO4 := 28.5·tpy	(Gas & Oil)	28.5·tpy·2190·hr·yr^{-1} = 1.625·lb·hr^{-1}	(Oil)
Be := 0.01·tpy	(Gas & Oil)	0.01·tpy·2190·hr·yr^{-1} = 0.001·lb·hr^{-1}	(Oil)
Hg := 0.01·tpy	(Gas & Oil)	0.01·tpy·2190·hr·yr^{-1} = 0.001·lb·hr^{-1}	(Oil)
Pb := 0.08·tpy	(Gas & Oil)	0.08·tpy·2190·hr·yr^{-1} = 0.005·lb·hr^{-1}	(Oil)

OUC - Indian River

From AP-42, 5th ed. (CTs C, D cont'd)

HCOH, only info is for SCR with water injection:

$HCOH := 0.0027 \cdot \frac{lb}{MMBtu} \cdot CT\_Btu\_Gas$ $HCOH = 3.7 \cdot \frac{lb}{hr}$ $HCOH \cdot 4390 \cdot \frac{hr}{yr} = 8.024 \cdot tpy$

Trace Elements, HAPS, not otherwise restricted by permit, distillate-oil fired:

$Sb := 2.2 \cdot 10^{-5} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu\_Oil$	$Sb = 0.03 \cdot lb \cdot hr^{-1}$	$Sb = 0.13 \cdot tpy$
$As := 4.9 \cdot 10^{-6} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu\_Oil$	$As = 0.007 \cdot lb \cdot hr^{-1}$	$As = 0.029 \cdot tpy$
$Cd := 4.2 \cdot 10^{-6} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu\_Oil$	$Cd = 0.006 \cdot lb \cdot hr^{-1}$	$Cd = 0.025 \cdot tpy$
$Cr := 4.7 \cdot 10^{-5} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu\_Oil$	$Cr = 0.063 \cdot lb \cdot hr^{-1}$	$Cr = 0.277 \cdot tpy$
$Co := 9.1 \cdot 10^{-6} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu\_Oil$	$Co = 0.012 \cdot lb \cdot hr^{-1}$	$Co = 0.054 \cdot tpy$
$Mn := 3.4 \cdot 10^{-4} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu\_Oil$	$Mn = 0.458 \cdot lb \cdot hr^{-1}$	$Mn = 2.006 \cdot tpy$
$Ni := 1.2 \cdot 10^{-3} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu\_Oil$	$Ni = 1.615 \cdot lb \cdot hr^{-1}$	$Ni = 7.079 \cdot tpy$
$P := 3.0 \cdot 10^{-4} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu\_Oil$	$P = 0.404 \cdot lb \cdot hr^{-1}$	$P = 1.77 \cdot tpy$
$Se := 5.3 \cdot 10^{-6} \cdot lb \cdot MMBtu^{-1} \cdot CT\_Btu\_Oil$	$Se = 0.007 \cdot lb \cdot hr^{-1}$	$Se = 0.031 \cdot tpy$

OUC - Indian River

Unpaved Roads

VMT := 216540·$\frac{mi}{yr}$·25·% VMT = 54135 ·$\frac{mi}{yr}$

k := 0.8 particle size multiplier, TSP. Use 0.36 for PM10 (AP-42, 4th ed.)
s := 5 silt content
S := 20 mean vehicle speed, mph
W := 5 mean vehicle weight, ton (includes some hvy eqpt + cars)
w := 5 mean number of wheels
p := 115.3 mean number days > 0.01 in. precipitation
Eff := 0·% Control by wetting

For TSP,

$E := 5.9 \cdot k \cdot \frac{s}{12} \cdot \frac{S}{30} \cdot \frac{W}{3}^{0.7} \cdot \frac{w}{4}^{0.5} \cdot \frac{365 - p}{365} \cdot \frac{lb}{mi}$ $E = 1.434 \cdot \frac{lb}{mi}$

VMT·E·(1 - Eff) = 38.812 ·tpy $20 \cdot \frac{mi}{hr} \cdot E \cdot (1 - Eff) = 28.678 \cdot \frac{lb}{hr}$

For PM10, k := 0.36

$E := 5.9 \cdot k \cdot \frac{s}{12} \cdot \frac{S}{30} \cdot \frac{W}{3}^{0.7} \cdot \frac{w}{4}^{0.5} \cdot \frac{365 - p}{365} \cdot \frac{lb}{mi}$ $E = 0.645 \cdot \frac{lb}{mi}$

VMT·E·(1 - Eff) = 17.465 ·tpy $20 \cdot \frac{mi}{hr} \cdot E \cdot (1 - Eff) = 12.905 \cdot \frac{lb}{hr}$

OUC - Indian River

Paved Roads

$VMT := 216540 \cdot \frac{mi}{yr} \cdot 75 \cdot \%$ $VMT = 162405 \cdot \frac{mi}{yr}$

TSP - use "local streets" lb/VMT factor, AP-42, 4th ed.

$0.053 \cdot \frac{lb}{mi} \cdot VMT = 4.304 \cdot tpy$ $20 \cdot mph \cdot 0.053 \cdot \frac{lb}{mi} = 1.06 \cdot \frac{lb}{hr}$

PM10 - use "local streets" lb/VMT factor, AP-42, 4th ed.

$0.018 \cdot \frac{lb}{mi} \cdot VMT = 1.462 \cdot tpy$ $20 \cdot mph \cdot 0.018 \cdot \frac{lb}{mi} = 0.36 \cdot \frac{lb}{hr}$

Maintenance Painting Activities (Contractor Data for 1994)

Assume same VOC content as for Stanton

$Q := 1389 \cdot \frac{gal}{yr} \cdot 1.1$ $Q = 1527.9 \cdot \frac{gal}{yr}$ Scaled to 10% more than 1994 for flexibility

$Q \cdot 3.5 \cdot \frac{lb}{gal} = 2.674 \cdot tpy$ based on maximum VOC content 3.5 lb/gal

$Hours := 8760 \cdot \frac{hr}{yr} \frac{8}{24} \frac{5}{7} \frac{1}{4}$ $Q \cdot 3.5 \cdot \frac{lb}{gal} \cdot \frac{1}{Hours} = 10.256 \cdot \frac{lb}{hr}$

Indian River Potential Emission Source Inventory

E.U.	Description	Status?	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr
			VOC		PM		PM10		S
E.U.	Description	Status?	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr
		I							
		I							
		P							
1	Unit 1 boiler	S	4.43	18.6	249.7	349.5	177.3	248.2	2289
2	Unit 2 boiler	S	10.73	45.1	604.9	846.9	429.5	601.3	5545
3	Unit 3 boiler	S	16.22	68.1	914.6	1280	649.4	909.2	8384
		P							
		P							
		P							
8	Lime Storage Silo	S			0.002	0.001	0.002	0.001	
4	Combustion Turbine (35 MW)	S	4	17.5	10	43.8	10	43.8	142.7
5	Combustion Turbine (35 MW)	S	4	17.5	10	43.8	10	43.8	142.7
7	Combustion Turbine (129 MW)	S	102.3	130.5	216.4	246.8	216.4	246.8	870.3
6	Combustion Turbine (129 MW)	S	102.3	130.5	216.4	246.8	216.4	246.8	870.3
		P							
		E							
		P							
		P							
		P							
		E							
		P							
		P							
	Unpaved Roads	S			28.7	38.8	12.9	17.5	
	Paved Roads	S			1.06	4.3	0.36	1.46	
		P							
		P							
		E							
		P							
		P							
	Painting applications for mainten	S	10.3	2.67					
		P							
	Totals	P	254.28	430.47	2251.762	3100.701	1722.262	2358.861	18244

tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
2	NOx		CO		Formaldehyde		Sb		As	
tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
9612	390.3	1639	34.62	145.4	0.337	1.42	0.038	0.161	0.095	0.398
23291	945.7	3972	89.95	377.8	0.817	3.43	0.093	0.39	0.23	0.965
35214	1430	6006	128.3	539	1.235	5.19	0.14	0.589	0.348	1.46
625	118.3	518.2	10.1	44.2	1.2	5.3	0.01	0.043	0.002	0.01
625	118.3	518.2	10.1	44.2	1.2	5.3	0.01	0.043	0.002	0.01
954.1	462.1	801.8	145.2	315.5	3.7	8.02	0.03	0.13	0.007	0.029
954.1	462.1	801.8	145.2	315.5	3.7	8.02	0.03	0.13	0.007	0.029
71275.2	3926.8	14257	563.47	1781.6	12.189	36.68	0.351	1.486	0.691	2.901

lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr
Be		Cd		Cr		Co		Pb		
lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr
0.003	0.015	0.176	0.737	0.107	0.447	0.101	0.423	0.208	0.874	0.062
0.008	0.036	0.425	1.787	0.258	1.084	0.244	1.025	0.504	2.117	0.149
0.013	0.054	0.643	2.702	0.39	1.639	0.369	1.549	0.762	3.201	0.226
0.0001	0.0005	0.002	0.008	0.021	0.092	0.004	0.018	0.026	0.113	0.151
0.0001	0.0005	0.002	0.008	0.021	0.092	0.004	0.018	0.026	0.113	0.151
0.009	0.01	0.006	0.025	0.063	0.277	0.012	0.054	0.073	0.08	0.458
0.009	0.01	0.006	0.025	0.063	0.277	0.012	0.054	0.073	0.08	0.458
0.0422	0.126	1.26	5.292	0.923	3.908	0.746	3.141	1.672	6.578	1.655

tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
n		Hg		Ni		Se		HCl		H2SO4
tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
0.259	0.027	0.112	1.99	8.34	0.032	0.133	30.8	129.2		
0.627	0.065	0.271	4.81	20.21	0.077	0.322	74.5	313		
0.948	0.098	0.41	7.27	30.55	0.116	0.487	112.7	473.3		
0.663	0	0.002	0.534	2.34	0.002	0.01				
0.663	0	0.002	0.534	2.34	0.002	0.01				
2.01	0.009	0.01	1.62	7.08	0.007	0.031			26	28.5
2.01	0.009	0.01	1.62	7.08	0.007	0.031			26	28.5
7.18	0.208	0.817	18.378	77.94	0.243	1.024	218	915.5	52	57

lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Phosphorous							
lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
0.133	0.585						
0.133	0.585						
0.266	1.17	0	0	0	0	0	0

Identification
- Identification No.: CT Tank
- City: Titusville
- State: FL
- Company: OUC - Indian River Plant
- Type of Tank: Vertical Fixed Roof

Tank Dimensions
- Shell Height (ft): 26
- Diameter (ft): 32
- Liquid Height (ft): 26
- Avg. Liquid Height (ft): 13
- Volume (gallons): 156437
- Turnovers: 700
- Net Throughput (gal/yr): 109505900 — Worst case for single tank assumes ALL No. 2 oil passes thrugh largest tank.

Paint Characteristics
- Shell Color/Shade: White/White
- Shell Condition: Good
- Roof Color/Shade: White/White
- Roof Condition: Good

Roof Characteristics
- Type: Dome
- Height (ft): 4.00
- Radius (ft) (Dome Roof): 16.00
- Slope (ft/ft) (Cone Roof): 0.0000

Breather Vent Settings
- Vacuum Setting (psig): -0.15
- Pressure Setting (psig): 0.15

Meteorological Data Used in Emission Calculations: Orlando, Florida

Fuel Oil No. 6

Worst case assumes entire throughput through single (largest) tank.

dentification

Identification No.:	Tank 3
City:	Titusville
State:	FL
Company:	OUC
Type of Tank:	Vertical Fixed Roof

ank Dimensions

Shell Height (ft):	32
Diameter (ft):	200
Liquid Height (ft):	32
Avg. Liquid Height (ft):	16
Volume (gallons):	7521020
Turnovers:	46
Net Throughput (gal/yr):	348223226

aint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

oof Characteristics

Type:	Dome
Height (ft):	5.00
Radius (ft) (Dome Roof):	100.0
Slope (ft/ft) (Cone Roof):	0.0000

eather Vent Settings

Vacuum Setting (psig):	-0.15
Pressure Setting (psig):	0.15

eteorological Data Used in Emission Calculations: Orlando, Florida

nual Emissions Report

quid Contents	Losses (lbs.): Standing	Withdrawal	Total
stillate fuel oil no. 2	33.80	730.99	764.79
tal:	33.80	730.99	764.79

ture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
tillate fuel oil no. 2	All	74.41	68.90	79.92	72.42	0.0103	0.0087	0.0122	130.000			130.00	Option 4: A=12.1010, B=8907.0

xture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
sidual Oil No. 6	All	120.00	114.49	125.51	72.42	0.0002	0.0002	0.0003	190.000			190.00	Option 4: A=10.1040, B=10475.0

ıual Emissions Report

ıuid Contents	Losses (lbs.): Standing	Withdrawal	Total
idual Oil No. 6	102.04	256.65	358.70
al:	102.04	256.65	358.70

$= 0.18$ tpy

RESIDUAL OIL NO. 6

T f	40	50	60	70	80	90	100	110	120	125	130
T r	500	510	520	530	540	550	560	570	580	585	590
P	0.00002	0.00003	0.00004	0.00006	0.00009	0.00013	0.00019	0.000213	0.00025	0.000269	0.000287

TABLE 12.3-2. PROPERTIES (M_V, W_{VC}, P_{VA}, W_L) OF SELECTED PETROLEUM LIQUIDS[a]

Petroleum liquid	Vapor molecular weight (at 60°F) M_V (lb/lb-mole)	Condensed vapor density (at 60°F) W_{VC} (lb/gal)	Liquid density, lb/gal at 60°F	True vapor pressure in psi at						
				40°C	50°F	60°F	70°F	80°F	90°F	100°F
Gasoline RVP 13	62	4.9	4.9	4.7	5.7	6.9	8.3	9.9	11.7	13.8
Gasoline RVP 10	66	5.1	5.1	3.4	5.7	5.2	6.2	7.4	8.8	10.5
Gasoline RVP 7	68	5.2	5.2	2.3	2.9	3.5	4.3	5.2	6.2	7.4
Crude Oil RVP 5	50	4.5	4.5	1.8	2.3	2.8	3.4	4.0	4.8	5.7
Jet naphtha (JP-4)	80	5.4	5.4	0.8	1.0	1.3	1.6	1.9	2.4	2.7
Jet kerosene	130	6.1	6.1	0.0041	0.0060	0.0085	0.011	0.015	0.021	0.029
Distillate fuel oil No. 2	130	6.1	6.1	0.0031	0.0045	0.0074	0.0090	0.012	0.016	0.022
Residual oil No. 6	190	6.4	6.4	0.00002	0.00003	0.00004	0.00006	0.00009	0.00013	0.00019

Notes:
[a]References 7 and 8.

APPENDIX M

TITLE VI INFORMATION

TITLE VI INFORMATION

As requested in the 'Facility Supplemental Information' section the following pieces of equipment may be found at the Indian River Plant Facility, and must be included within the Title V application:

EQUIPMENT	REFRIGERANT	AMOUNT
Office Unit	R12	100 lbs.
Unit 1 Computer Room	R12	50 lbs.
Control Room Unit	R12	50 lbs.
Unit 3 Lab	R22	90 lbs.

Recovery Unit: National Refrigeration Products
Model/Year: LV 8 / 1994
Serial Number: 107339
Certified: ARI for R12, R22, R500, R502, R134a