

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 17-Nov-1998 08:45am
From: Mary Fillingim TAL
FILLINGIM_M
Dept: Air Resources Management
Tel No: 850/488-0114

To: See Below
Subject: New Posting #0310045

There is a new posting on Florida's website.

0310045002AV
NORTHSIDE/SJRPP

Proposed

The notification letter is encoded and attached. If you have any questions, feel free to contact me.

Thanks,
Mary

Distribution:

To:	adams yolanda	(adams.yolanda@epamail.epa.gov@in)
To:	pierce carla	(pierce.carla@epamail.epa.gov@in)
To:	Barbara Boutwell TAL	(BOUTWELL_B)
To:	Scott Sheplak TAL	(SHEPLAK_S)
To:	Terry Knowles TAL	(KNOWLES_T)
To:	danois gracy	(danois.gracy@epamail.epa.gov@in)
To:	Elizabeth Walker TAL	(WALKER_E)
CC:	Bruce Mitchell TAL	(MITCHELL_B)

STATEMENT OF BASIS

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park
Facility ID No.: 0310045
Duval County

Title V Air Operation Permit Revision
PROPOSED Permit No.: 0310045-002-AV

This Title V air operation permit revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The purpose of the revision is to incorporate the Phase I/II NO_x standards into the Title IV Acid Rain Part pursuant to Rule 62-214.360(6), F.A.C. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

This facility consists of five boilers, Northside Generating Station (NGS) Boilers Nos. 1, 2 and 3 (**No. 2 was placed on long-term reserve shutdown on March 1, 1984**) and St. Johns River Power Park (SJRPP) Boilers Nos. 1 and 2; four combustion turbines, NGS Nos. 3, 4, 5 and 6 (Nos. 1 and 2 are inactive); and, an auxiliary boiler, NGS No. 1 (SJRPP Nos. 1 and 2 have been removed from service and dismantled). The NGS auxiliary boiler is allowed to operate when one of the main boilers are shut down or in a startup mode prior to being put on line. Emissions from the NGS Boilers Nos. 1, 2 and 3, are uncontrolled. Emissions from the auxiliary boiler and the NGS CTs Nos. 3, 4, 5 and 6, are controlled firing low sulfur fuel oil. Emissions from the SJRPP Boilers Nos. 1 and 2 are controlled with an electrostatic precipitator, a limestone scrubber, and low-NO_x burners. The SJRPP facility also includes coal, limestone and flyash handling activities, of which various control devices, control strategies, and control techniques are required. Also, included in this permit are miscellaneous unregulated/exempt emissions units and/or activities.

NGS Boiler No. 1 is a fossil fuel-fired steam generator with a nominal nameplate rating of 297.5 megawatts (electric). The emissions unit will be allowed to fire new No. 6 residual fuel oil, natural gas, LP gas, "on-specification" used oil, landfill gas, and a blend of fuel oil and natural gas and/or landfill gas. The maximum heat inputs are (1) 2767 MMBtu per hour when firing fuel oil; (2) 2892 MMBtu per hour when firing natural gas or natural/landfill gases; or (3) 2767 - 2892 MMBtu per hour when firing a combination of fuel oil and natural gas or natural/landfill gases, respectively. LP gas is used as the igniter fuel when natural gas is not available. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Pollutant emissions from this emissions unit are uncontrolled. The combustion gases exhaust through a single stack of 250 feet. NGS Boiler No. 1 began commercial operation in 1966.

Statement of Basis (cont.)

Jacksonville Electric Authority

Northside Generating Station/St. Johns River Power Park

PROPOSED Permit No.: 0310045-002-AV

Page 2 of 4

NGS Boiler No. 2 is a fossil fuel-fired steam generator with a nominal nameplate rating of 297.5 megawatts (electric). The emissions unit is permitted to fire new No. 6 residual fuel oil, natural gas, and a blend of fuel oil and natural gas. The maximum heat inputs are (1) 2341 MMBtu per hour when firing fuel oil; (2) 2352 MMBtu per hour when firing natural gas; or (3) 2341 - 2352 MMBtu per hour when firing a combination of No. 6 fuel oil and natural gas, respectively. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Pollutant emissions from this emissions unit are uncontrolled. The combustion gases exhaust through a single stack of 300 feet. NGS Boiler No. 2 began commercial operation in November 1966. **NGS Boiler No. 2 was placed on long-term reserve shutdown on March 1, 1984.**

NGS Boiler No. 3 is a fossil fuel-fired steam generator with a nominal nameplate rating of 563.7 megawatts (electric). The emissions unit will be allowed to fire new No. 6 residual fuel oil, natural gas, LP gas, "on-specification" used oil, landfill gas, and a blend of fuel oil and natural gas and/or landfill gas. The maximum heat inputs are (1) 5033 MMBtu per hour when firing fuel oil; (2) 5260 MMBtu per hour when firing natural gas or natural/landfill gases; or (3) 5033 - 5260 MMBtu per hour when firing a combination of fuel oil and natural gas or natural/landfill gases, respectively. LP gas is used as the igniter fuel when natural gas is not available. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Pollutant emissions from this emissions unit are uncontrolled. The combustion gases exhaust through two stacks of 300 feet. NGS Boiler No. 3 began commercial operation in 1977.

The NGS boilers are regulated under Acid Rain, Phase II; Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and, Rule 62-296.702, F.A.C., Fossil Fuel Steam Generators.

The NGS auxiliary boiler No. 1 is steam generator that is allowed to fire natural gas, LP gas, new No. 2 distillate or new No. 6 residual fuel oils, and a blend of new fuel oil(s) with internally generated waste oil that does not contain any polychlorinated biphenyls (PCBs). The maximum fuel oil sulfur content is 1.8%, by weight (BACT dated October 15, 1984). Emissions from this boiler are uncontrolled. The NGS Auxiliary Boiler No. 1 was authorized construction on October 15, 1984. This emissions unit can only be operated when one of the main NGS boilers (No. 1, 2 or 3) is either shut down or is in the startup mode of operation prior to being on line *or* when electrical power demand requires that all three main boilers (NGS Nos. 1, 2 and 3) and the auxiliary boiler (NGS No. 1) to be on line.

The NGS auxiliary boiler No. 1 is regulated under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 million Btu per Hour Heat Input, which includes BACT (dated October 15, 1984).

Statement of Basis (cont.)
Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park
PROPOSED Permit No.: 0310045-002-AV
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The NGS combustion turbines Nos. 3, 4, 5 and 6 are identical emissions units manufactured by General Electric (Model MS 7000) and are designated as, respectively. Each CT has a maximum heat input from (virgin) new No. 2 distillate fuel oil of 901.0 MMBtu (LHV: lower heating value). The No. 2 fuel oil has a maximum sulfur content of 0.5%, by weight. These CTs are used as peaking units during peak demand times, during emergencies and during controls testing, to run a nominal 56.2 MW generator (each). Emissions from the CTs are uncontrolled. A group of exhaust stacks serve the CTs. CT No. 3 began commercial service in February 1975, No. 4 in January 1975, and Nos. 5 and 6 in December 1974

The NGS CTs are regulated under Rule 62-210.300, F.A.C., Permits Required. These emissions units are not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines.

The SJRPP Boilers Nos. 1 and 2 are fossil fuel-fired steam generators, each having a nominal nameplate rating of 679.6 megawatts (electric). The emissions units will be allowed to fire pulverized coal, a blend of petroleum coke and coal, new No. 2 distillate fuel oil (startup and low-load operation), and "on-specification" used oil. The maximum heat input to each emissions unit is 6,144 million Btu per hour. SJRPP Boilers Nos. 1 and 2 are dry bottom wall-fired boilers and will use an electrostatic precipitator (ESP) to control particulate matter, a wet limestone flue gas desulfurization (FGD) unit to control sulfur dioxide, low NO_x burners and low excess-air firing to control nitrogen oxides, and good combustion to control carbon monoxide (CO). Each boiler exhausts through its own stack (640 feet above grade). SJRPP Boiler No. 1 began commercial operation in March 1986. SJRPP Boiler No. 2 began commercial operation in May 1988.

The SJRPP boilers are regulated under Acid Rain, Phase II for SO₂ and Phase I/II for NO_x; NSPS - 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration [PSD; PSD-FL-010; PSD-FL-010(A & B)]; and, Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated May 7, 1981.

The SJRPP Boilers Nos. 1 and 2 had a CO limitation and testing requirement imposed on them in the initial Title V operation permit that went final on December 31, 1997. Based on a review of the BACT and PSD files, the U.S. EPA Region 4 decided when it issued PSD-FL-010 not to impose a CO limitation and relegate the control of CO to good combustion. Therefore, the CO limitation and testing requirement have been deleted.

The coal receiving, storage and transfer systems at the coal storage yard support the operation of the two SJRPP power boilers. Particulate matter emissions are controlled using fabric filter systems, water sprays, wetting agents, and full enclosures or partial enclosures, where appropriate.

Statement of Basis (cont.)
Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park
PROPOSED Permit No.: 0310045-002-AV
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The coal receiving, storage and transfer systems at the coal storage yard are regulated under NSPS - 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Prevention of Significant Deterioration (PSD): PSD-FL-010 dated March 12, 1982; Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated May 7, 1981; and, PPSA : PA 81-13 (revised 08/01/95).

Fugitive particulate matter emissions will be generated from limestone and flyash handling and storage systems at the SJRPP. Various control strategies that will be used to minimize emissions are enclosures, wet suppression sprays, and control systems like baghouses. Visible emissions limits will generally be used to indicate compliance, with mass tests as backup requirements where visible emissions limits are violated. The emissions units are regulated under Rule 62-212.400(5), PSD NSR Review, which includes BACT (dated 05/07/81; PSD-FL-010 was issued March 12, 1982).

The heat input limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emissions limits and to aid in determining future rule applicability. A note below the permitted capacity condition clarifies this. Regular record keeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required to demonstrate at what percentage of the rated capacity that the emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of process variables for emissions tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.

Based on the initial Title V permit application received June 14, 1996, this facility is a major source of hazardous air pollutants (HAPs).



Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

November 16, 1998

CERTIFIED MAIL - Return Receipt Requested

Mr. Walter P. Bussels
Managing Director
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

Re: PROPOSED Title V Permit No.: 0310045-002-AV
Jacksonville Electric Authority: Northside Generating Station/St. Johns River Power Park

Dear Mr. Bussels:

One copy of the "PROPOSED PERMIT DETERMINATION" for the Jacksonville Electric Authority Northside Generating Station/St. Johns River Power Park located at 4377 Hecksher Drive, Jacksonville, Duval County, is enclosed. This letter is only a courtesy to inform you that the DRAFT permit has become a PROPOSED permit.

An electronic version of this determination has been posted on the Division of Air Resources Management's world wide web site for the United States Environmental Protection Agency (USEPA) Region 4 office's review. The web site address is http://www2.dep.state.fl.us/air/enhanced/Title_V/Permits.

Pursuant to Section 403.0872(6), Florida Statutes, if no objection to the PROPOSED permit is made by the USEPA within 45 days, the PROPOSED permit will become a FINAL permit no later than 55 days after the date on which the PROPOSED permit was mailed (posted) to USEPA. If USEPA has an objection to the PROPOSED permit, the FINAL permit will not be issued until the permitting authority receives written notice that the objection is resolved or withdrawn.

If you should have any questions, please contact Bruce Mitchell at 850/921-9506.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/BM/m

Enclosures

Copy furnished to:

Mr. Jon P. Eckenbach, Executive Vice President/Designated Representative, JEA
Mr. Richard Breitmoser, P.E., JEA
Mr. Bert Gianazza, JEA, Application Contact
Mr. James L. Manning, AWQD
Ms. Carla E. Pierce, U.S. EPA, Region 4 (INTERNET E-mail Memorandum)
Ms. Gracy R. Danois, U.S. EPA, Region 4 (INTERNET E-mail Memorandum)

11/18/98

cc: Bruce Mitchell
Reading File

"Protect, Conserve and Manage Florida's Environment and Natural Resources"

Is your RETURN ADDRESS completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. Addressee's Address
2. Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
 Mr. Walter P. Bussels
 Managing Director
 Jacksonville Electric Authority
 21 West Church Street
 Jacksonville, Florida 32202

4a. Article Number
 P 263 584 708

4b. Service Type
 Registered Certified
 Express Mail Insured
 Return Receipt for Merchandise COD

7. Date of Delivery
 11-20-98

5. Received By: (Print Name)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature: (Addressee or Agent)

Paul J. Campbell

PS Form 3811, December 1994

102595-97-B-0179

Domestic Return Receipt

Thank you for using Return Receipt Service.

P 263 584 708

**US Postal Service
 Receipt for Certified Mail**

No Insurance Coverage Provided.
 Do not use for International Mail (See reverse)

Sent to	Mr. Walter P. Bussels
Street & Number	21 West Church Street
Post Office, State, & ZIP Code	Jacksonville, Florida 32202
Postage	\$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	\$
Postmark or Date	11/18/98
JEA-Northside/St. John's Facility ID#0310045-002-AV	

PS Form 3800, April 1995

PROPOSED PERMIT DETERMINATION

Jacksonville Electric Authority: Northside Generating Station/St. Johns River Power Park

PROPOSED Permit No.: 0310045-002-AV

I. Public Notice.

An "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" to Jacksonville Electric Authority for the Northside Generating Station/St. Johns River Power Park located at 4377 Hecksher Drive, Jacksonville, Duval County, was clerked on October 14, 1998. The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was published in the The Florida Times-Union on October 14, 1998. The DRAFT Title V Air Operation Permit was available for public inspection at the City of Jacksonville Air & Water Quality Division in Jacksonville and the permitting authority's office in Tallahassee. Proof of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was received on November 16, 1998.

II. Public Comment(s).

Comments were received and the DRAFT Title V Operation Permit was changed. The comments were not considered significant enough to reissue the DRAFT Title V Permit and require another Public Notice. Comments were received from one respondent during the 30 (thirty) day public comment period. Listed below is the comment letter and a response to each comment in the order that the comment was received. The comment(s) will not be restated. Where duplicative comments exist, the original response is referenced.

Comments were received from:

A. Memorandum to file from Bruce Mitchell dated November 13, 1998.

I. A new specific condition is to be added to Section III. Subsection D., No. D.74., in order to establish the appropriate test procedures for the analysis of sulfur for the fuels allowed to be fired in the boilers.

The specific condition will read as follows:

D.74. Fuel - Sulfur Content. (see specific condition D.13.)

a. Coal or Coal - Petroleum Coke Blend. The as-fired fuel sulfur content, percent by weight, for the coal or coal - petroleum coke blend shall be determined using ASTM D2013-72 and either ASTM D3177-75, ASTM D4239-85, ASTM D3176-74, or the latest edition, to analyze a representative sample of the fuel being fired; or, the operation of an inlet SO₂ analyzer with support provided from a vendor's supplied analysis for each shipment of fuel delivered shall be used to establish the sulfur content, percent by weight, of the fuel being fired.

b. No 2. Fuel Oil. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, ASTM D1552-95, both ASTM D4057-88 and ASTM D129-91, or the latest edition. The permittee shall have an as-fired sample analyzed after each fuel delivery or the vendor shall provide an analysis including sulfur content and heating value for each fuel delivery. However, if the No. 2 fuel oil being delivered has a sulfur content of 0.76 % or less, by weight, then the vendor's analysis is acceptable and no further analysis is required.

[Rules 62-213.440 and 62-297.440, F.A.C.; 40 CFR 60.17; and, 40 CFR 60.47a]

PROPOSED Permit Determination

JEA: Northside Generating Station/St. Johns River Power Park

PROPOSED Permit No.: 0310045-002-AV

Page 2 of 2

2. Since the emissions units in Section III. Subsection D., are not existing emissions units subject to soot blowing requirements, Specific Condition No. D.50.(a)2. is not applicable and will be deleted from the text. The text to be deleted (in bold) reads as follows:

D.50. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

3. In Section III. Subsection D., Specific Condition No. D.60., a reference in the text was made to "40 CFR 60.49(a)" and should have been "40 CFR 60.49a". This correction has been made.

4. Based on objections and comments received from U.S. EPA Region 4 regarding the PROPOSED Title V permit for FP&L's Cape Canaveral plant, the following changes will be made:

a. In Section II., Facility-wide Conditions., Condition No. 12, "Operating Source Section" will be replaced with "Air & RPCRA Enforcement Branch, Air Compliance Section" and the complete address will read as follows:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air & EPCRA Enforcement Branch
Air Compliance Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9099
Fax: 404/562-9095

b. A request was made to link some specific conditions in order to see the ties between them. Therefore, the following specific conditions will include some linkage:

- (1) Linkage between specific conditions: A.31. with A.32. and A.33.
- (2) Linkage between specific conditions: B.18. with B.19.
- (3) Linkage between specific conditions: C.15. with C.16.
- (4) Linkage between specific conditions: D.50. with D.51.

B. Document(s) on file with the permitting authority:

-Memorandum to file from Bruce Mitchell dated November 13, 1998.

III. Conclusion.

The permitting authority hereby issues the PROPOSED Permit No.: 0310045-002-AV, with any changes noted above.

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park
Facility ID No.: 0310045
Duval County

Title V Air Operation Permit Revision
PROPOSED Permit No.: 0310045-002-AV

Permitting Authority:

State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-1344
Fax: 850/922-6979

Compliance Authority:

City of Jacksonville
Regulatory and Environmental Services Department
Air and Water Quality Division
421 West Church Street, Suite 422
Jacksonville, Florida 32202-4111
Telephone: 904/630-3484
Fax: 904/630-3638

Title V Air Operation Permit
PROPOSED Permit No.: 0310045-002-AV

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Permittee:

Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

PROPOSED Permit No.: 0310045-002-AV**Facility ID No.:** 0310045**SIC No.:** 49; 4911**Project:** Title V Air Operation Permit Revision

This permit revision is for the inclusion of the Phase I/II NOx limitations pursuant to Rule 62-214.360(6), Florida Administrative Code (F.AC.), into the Title IV Acid Rain Part for the Jacksonville Electric Authority's Northside Generating Station/St. Johns River Power Park. This facility is located at 4377 Heckshire Drive, Jacksonville, Duval County; UTM Coordinates: Zone 17, 446.90 km East and 3359.150 km North; Latitude: 30° 21' 52" North and Longitude: 81° 37' 25" West.

This Title V air operation permit revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.); Chapters 62-4, 62-210, 62-213 and 62-214, F.A.C.; the City of Jacksonville Ordinance Code (JOC), Title X, Chapter 376; and, the Jacksonville Environmental Protection Board (JEPB) Rule 2, Parts I thru VII and Parts IX thru XII. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:

Appendix U-1, List of Unregulated Emissions Units and/or Activities

Appendix I-1, List of Insignificant Emissions Units and/or Activities

APPENDIX TV-1, TITLE V CONDITIONS (version dated 12/02/97)

APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)

TABLE 297.310-1, CALIBRATION SCHEDULE (dated 10/07/96)

FIGURE 1 - SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSIONS
AND MONITORING SYSTEMS PERFORMANCE REPORT (40 CFR 60, July 1996)

Operation and Maintenance Plan

Alternate Sampling Procedure: ASP Number 97-B-01

Appendix 40CFR60 Subpart A - General Provisions (dated 07/23/97)

Attachment NGS: CT Heat Input Nominal Values

Attachment SJRPP: Material Handling Transfer Points

Attachment SJRPP: Protocol for Startup and Shutdown

Effective Date: January 1, 1999**Renewal Application Due Date:** July 5, 2003**Expiration Date:** December 31, 2003

Howard L. Rhodes, Director
Division of Air Resources Management

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of five boilers, Northside Generating Station (NGS) Boilers Nos. 1, 2 and 3 (**No. 2 was placed on long-term reserve shutdown on March 1, 1984**) and St. Johns River Power Park (SJRPP) Boilers Nos. 1 and 2; four combustion turbines, NGS Nos. 3, 4, 5 and 6 (Nos. 1 and 2 are inactive); and, an auxiliary boiler, NGS No. 1. The NGS auxiliary boiler is allowed to operate when one of the main boilers is shut down or in a startup mode prior to being put on line. Emissions from the NGS Boilers Nos. 1, 2 and 3, are uncontrolled. Emissions from the auxiliary boilers and the NGS CTs Nos. 3, 4, 5 and 6, are controlled firing low sulfur fuel oil. Emissions from the SJRPP Boilers Nos. 1 and 2 are controlled with an electrostatic precipitator, a limestone scrubber, and low-NO_x burners. The SJRPP facility also includes coal, petroleum coke, limestone and flyash handling activities, of which various control devices, control strategies, and control techniques are required. Also, included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the initial Title V permit application received June 14, 1996, this facility is a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U.

<u>ID No.</u>	<u>Brief Description</u>
-001	NGS Boiler No. 1
-002	NGS Boiler No. 2 (on long-term reserve shutdown since 03/01/84)
-003	NGS Boiler No. 3
-004	NGS Combustion Turbine No. 1 (inactive: permit surrendered and dismantled)
-005	NGS Combustion Turbine No. 2 (inactive: permit surrendered and dismantled)
-006	NGS Combustion Turbine No. 3
-007	NGS Combustion Turbine No. 4
-008	NGS Combustion Turbine No. 5
-009	NGS Combustion Turbine No. 6
-013	NGS Auxiliary Boiler No. 1
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2
-018	SJRPP Auxiliary Boilers Nos. 1 and 2 (inactive: dismantled)
-022	SJRPP Limestone and Flyash Handling
-023	SJRPP Coal Storage Yard and Transfer Systems
-024	SJRPP Cooling Towers (2)

Unregulated Emissions Units and/or Activities

{Permitting note: For Unregulated Emissions Units and/or Activities, see Appendix U-1 (attached).}

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:

Table 1-1, Summary of Air Pollutant Standards and Terms

Table 2-1, Summary of Compliance Requirements

Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers

Appendix H-1, Permit History/ID Number Changes

These documents are on file with the permitting authority:

BACT Determinations dated 10/15/84 (NGS) and 05/07/81 (SJRPP).

Phase II SO₂ Acid Rain Application/Compliance Plan received 12/26/95.

Initial Title V Permit Application received 06/14/96.

Supplementary information received 09/16/96.

PSD-FL-010(B) issued 10/14/96.

Supplementary information received 01/09/97.

Supplementary information received 09/17/97.

ORDER EXTENDING PERMIT EXPIRATION DATE dated 11/13/97.

Phase I/II NO_x Acid Rain Compliance Plan dated 12/19/97.

Supplementary information received 04/23/98.

Supplementary information received 07/13/98.

Supplementary information (Fax) received 08/05/98.

Supplementary information (Fax) received 10/12/98.

Memorandum to file from Bruce Mitchell dated 11/13/98.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-1, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-1, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}
2. **Not federally enforceable.** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.; and, Jacksonville Environmental Protection Board (JEPB) Rule 2, Part IX]
3. **Not federally enforceable.** Odor Nuisance. Pursuant to JOC Chapter 376, any facility that causes or contributes to the emission of objectionable odors which results in the City of Jacksonville Air and Water Quality Division (AWQD) receiving and validating complaints from five (5) or more different households within a 90 day period and can be cited for objectionable odors.
[JOC Chapter 376]
4. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)1. & 4., F.A.C.; and, Part X, Rule 2.1001, JEPB]
5. Prevention of Accidental Releases (Section 112(r) of CAA). If required by 40 CFR 68, the permittee shall submit to the implementing agency:
 - a. a risk management plan (RMP) when, and if, such requirement becomes applicable; and,
 - b. certification forms and/or RMPs according to the promulgated rule schedule.[40 CFR 68]
6. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]
7. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

8. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.

{Permitting note: There are no requirements deemed necessary and ordered by the Department at this time.}

[Rule 62-296.320(1)(a), F.A.C.; and, Part X, Rule 2.1001, JEPB]

9. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include: chemical or water application to unpaved roads or unpaved yard areas; paving and maintenance of roads, parking areas and plant grounds; landscaping and planting of vegetation; confining abrasive blasting where possible; and other techniques, as necessary. Also, for the solid waste disposal area, wetting agents shall be applied.

[Rule 62-296.320(4)(c)2., F.A.C.; Part X, Rule 2.1001, JEPB; and, PSD-FL-010 and PA 81-13]

10. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.

[Rule 62-213.440, F.A.C.]

11. The permittee shall submit all compliance related notifications and reports required of this permit to the AWQD office at the following address:

City of Jacksonville
Regulatory and Environmental Services Department
Air and Water Quality Division
421 West Church Street, Suite 422
Jacksonville, Florida 32202-4111
Telephone: 904/630-3484
Fax: 904/630-3638

12. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air & EPCRA Enforcement Branch
Air Compliance Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9099
Fax: 404/562-9095

Section III. Emissions Units.

Subsection A. This section addresses the following emissions units.

E.U. ID

<u>No.</u>	<u>Brief Description</u>
-001	NGS Boiler No. 1
-002	NGS Boiler No. 2
-003	NGS Boiler No. 3

NGS Boiler No. 1 is a fossil fuel-fired steam generator with a nominal nameplate rating of 297.5 megawatts (electric). The emissions unit will be allowed to fire new No. 6 residual fuel oil, natural gas, LP gas, "on-specification" used oil, landfill gas, and a blend of fuel oil and natural gas and/or landfill gas. The maximum heat inputs are (1) 2767 MMBtu per hour when firing fuel oil; (2) 2892 MMBtu per hour when firing natural gas or natural/landfill gases; or (3) 2767 - 2892 MMBtu per hour when firing a combination of fuel oil and natural gas or natural/landfill gases, respectively. LP gas is used as the igniter fuel when natural gas is not available. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Pollutant emissions from this emissions unit are uncontrolled. The combustion gases exhaust through a single stack of 250 feet. NGS Boiler No. 1 began commercial operation in 1966.

NGS Boiler No. 2 is a fossil fuel-fired steam generator with a nominal nameplate rating of 297.5 megawatts (electric). The emissions unit is permitted to fire new No. 6 residual fuel oil, natural gas, and a blend of fuel oil and natural gas. The maximum heat inputs are (1) 2341 MMBtu per hour when firing fuel oil; (2) 2352 MMBtu per hour when firing natural gas; or (3) 2341 - 2352 MMBtu per hour when firing a combination of No. 6 fuel oil and natural gas, respectively. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Pollutant emissions from this emissions unit are uncontrolled. The combustion gases exhaust through a single stack of 300 feet. NGS Boiler No. 2 began commercial operation in November 1966. **NGS Boiler No. 2 was placed on long-term reserve shutdown on March 1, 1984.**

NGS Boiler No. 3 is a fossil fuel-fired steam generator with a nominal nameplate rating of 563.7 megawatts (electric). The emissions unit will be allowed to fire new No. 6 residual fuel oil, natural gas, LP gas, "on-specification" used oil, landfill gas, and a blend of fuel oil and natural gas and/or landfill gas. The maximum heat inputs are (1) 5033 MMBtu per hour when firing fuel oil; (2) 5260 MMBtu per hour when firing natural gas or natural/landfill gases; or (3) 5033 - 5260 MMBtu per hour when firing a combination of fuel oil and natural gas or natural/landfill gases, respectively. LP gas is used as the igniter fuel when natural gas is not available. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Pollutant emissions from this emissions unit are uncontrolled. The combustion gases exhaust through two stacks of 300 feet. NGS Boiler No. 3 began commercial operation in 1977.

{Permitting note(s): These emissions units are regulated under Acid Rain, Phase II; Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and, Rule 62-296.702, F.A.C., Fossil Fuel Steam Generators.}

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum operation heat input rates are as follows:

<u>Emissions Unit</u>	<u>MMBtu/hr Heat Input</u>	<u>Fuel Type</u>
NGS Boiler No. 1	2892	Natural Gas
	2892	Landfill Gas
	2767	New No. 6 Fuel Oil
	2767	"On-specification" Used Oil
	2767-2892	Fuel Oil and Natural Gas
	2767-2892	Fuel Oil and Natural/Landfill Gases
NGS Boiler No. 2	2352	Natural Gas
	2341	New No. 6 Fuel Oil
	2341-2352	New No. 6 Fuel Oil and Natural Gas
NGS Boiler No. 3	5260	Natural Gas
	5260	Landfill Gas
	5033	New No. 6 Fuel Oil
	5033	"On-specification" Used Oil
	5033-5260	Fuel Oil and Natural Gas
	5033-5260	Fuel Oil and Natural/Landfill Gases

Note: When a blend of fuel oil and natural and/or landfill gas is fired, the heat input is prorated based on the percent heat input of each fuel.

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.; and, AO16-194743, AO16-178094 and AO16-207528]

A.2. Emissions Unit Operating Rate Limitation After Testing. See specific conditions **A.26.** and **A.27.**

[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation - Fuels.

a. The only fuels allowed to be burned are natural gas, LP gas, landfill gas, new No. 6 fuel oil, "on-specification" used oil, and a blend of fuel oil and natural gas and/or landfill gas. "On-specification" used oil containing any quantifiable levels of PCBs can only be fired when the emissions unit is at normal operating temperatures. LP gas is used as the igniter fuel when natural gas is not available.

b. The total station (NGS Boilers Nos. 1, 2 and 3, and NGS Auxiliary Boiler No. 1) residual fuel oil consumption must not exceed 1,440,000 pounds in any consecutive three (3) hour period. [Rule 62-213.410, F.A.C.; 40 CFR 271.20(e)(3); AO16-194743, AO16-178094 and AO16-207528; AC16-85951 and BACT; and, applicant request dated June 14, 1996.]

A.4. Hours of Operation. The emissions units may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200(PTE), F.A.C.; and, AO16-194743, AO16-178094 and AO16-207528]

Emission Limitations and Standards

{Permitting Note: The attached Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A.5. Visible Emissions. For Boilers Nos. 1 and 3, visible emissions shall not exceed 40 percent opacity. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C. [Rules 62-296.405(1)(a) and 62-296.702(2)(b), F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-194743 and AO16-207528]

A.6. Visible Emissions. For Boiler No. 2, visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C. [Rules 62-296.405(1)(a) and 62-296.702(2)(b), F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-178094]

A.7. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more. [Rule 62-210.700(3), F.A.C; and, Part III, Rule 2.301, JEPB]

A.8. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods. See specific condition A.22. [Rules 62-296.405(1)(b) and 62-296.702(2)(a), F.A.C.; and, Part X, Rule 2.1001, JEPB]

A.9. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. [Rule 62-210.700(3), F.A.C.; and, Part III, Rule 2.301, JEPB]

A.10. Sulfur Dioxide. SO₂ emissions shall not exceed 1.98 pounds per million Btu heat input, as measured by applicable compliance methods. Any calculations or methods used to demonstrate compliance shall be based on the total heat input from all fossil fuels, including natural gas, and the sulfur from all fuels fired. See specific conditions A.17., A.23. and A.24. [Rules 62-213.440 and 62-296.405(1)(c)1.a., F.A.C.; and, Part X, Rule 2.1001, JEPB]

A.11. Sulfur Dioxide - Sulfur Content. For Boilers Nos. 1 and 3, the sulfur content of the as-fired No. 6 fuel oil shall not exceed 1.8 percent, by weight, if the SO₂ continuous emissions monitor system is temporarily inoperative. For Boiler No. 2, the maximum sulfur content shall not exceed 1.8%, by weight. See specific conditions A.17. and A.24. [Rule 62-296.405(1)(e)3., F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-178094 and AO16-207528]

A.12. Nitrogen Oxides (expressed as NO₂). For Boiler No. 3, nitrogen oxides shall not exceed 0.30 lb/MMBtu heat input, as measured by applicable compliance methods. See specific condition A.18. [Rule 62-296.405(1)(d)1., F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-207528]

A.13. "On-Specification" Used Oil. The burning of "on-specification" used oil is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:

a. Only "on-specification" used oil generated by the Jacksonville Electric Authority in the production and distribution of electricity shall be fired in these emissions units. The total combined quantity allowed to be fired in these emissions units shall not exceed 1,000,000 gallons per calendar year. "On-specification" used oil is defined as each used oil delivery that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" oil and shall not be fired. See specific conditions A.34., A.38. and A.39.

<u>CONSTITUENT / PROPERTY*</u>	<u>ALLOWABLE LEVEL</u>
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash Point	100 °F minimum
PCBs	less than 50 ppm

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).
[40 CFR 279.11]

Excess Emissions

A.14. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

A.15. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.

[Rule 62-210.700(2), F.A.C.; and, Part III, Rule 2.301, JEPB]

A.16. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

[Rule 62-210.700(4), F.A.C.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

A.17. Sulfur Dioxide.

a. For Boilers Nos. 1 and 3, the permittee elected to monitor emissions using a SO₂ continuous emissions monitoring system (CEMS). This procedure is allowed because the emissions units do not have an operating flue gas desulfurization device. See specific conditions **A.10.**, **A.11.**, **A.23.** and **A.24.**

b. Boiler No. 2 has been on long-term reserve shutdown since March 1, 1984.

c. The CEMS shall be calibrated, operated and maintained in accordance with the quality assurance requirements of 40 CFR 75, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and demonstrated based on a 24-hour daily average. A Relative Accuracy Testing Audit (RATA) shall be performed no less than annually.

d. In the event the CEMS becomes temporarily inoperable or interrupted, the fuels and the maximum fuel oil to natural gas firing ratio that can be used is that which was last used to demonstrate compliance prior to the loss of the CEMS, or the emissions units shall fuel switch and be fired with a fuel oil containing a maximum sulfur content of 1.8%, by weight, or less.

e. In the event of natural gas disruption and the emissions units have to fire 100% fuel oil, the emissions units shall be fired with a fuel oil containing a maximum sulfur content of 1.8%, by weight, or less.

[Rules 62-213.440, 62-204.800, 62-296.405(1)(c)3., and 62-296.405(1)(f)1.b., F.A.C.; and, AO16-194743 and AO16-207528]

A.18. **Nitrogen Oxides.** For Boiler No. 3, compliance with the nitrogen oxides (expressed as NO₂) limit of 0.30 lb/MMBtu shall be demonstrated by the following:

a. Through the use of a CEMS installed, calibrated, operated and maintained in accordance with the quality assurance requirements of 40 CFR 60, Appendix F, and 40 CFR 75, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and demonstrated based on a 30-day rolling average.

b. The performance specifications, location of the monitor, data requirements, data reduction and reporting requirements shall conform with the requirements of 40 CFR 51, Appendix P, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and 40 CFR 60, Appendix B, adopted by reference in Rule 62-204.800, F.A.C.

[Rules 62-296.405(1)(e)4. and 62-296.405(1)(f), F.A.C.; Part X, Rule 2.1001, JEPB; and, 40 CFR 60 & 75]

A.19. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

{Permitting Note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A.20. Visible emissions.

a. For Boilers Nos. 1 and 3, the test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C.

b. For Boiler No. 2, the test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. See specific condition **A.21**.

c. The visible emissions test(s) required shall be conducted simultaneously with particulate matter testing and soot blowing and non-soot blowing operating modes.

d. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rule 62-296.405(1)(e)1. & 5., F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-194743, AO16-178094 and AO16-207528]

A.21. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

[Rule 62-297.401, F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.22. Particulate Matter.

a. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 (with Orsat analysis) or 3A shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.

b. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rules 62-213.440, 62-296.405(1)(e)2. & 5., and 62-297.401, F.A.C.; Part X, Rule 2.1001, JEPB and, Part XI, Rule 2.1101, JEPB]

A.23. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards.

a. For Boilers Nos. 1 and 3, the permittee shall demonstrate compliance with the 1.98 lbs/MMBtu heat input standard by either using the above referenced EPA test methods, including if used during a RATA for the SO₂ CEMS, or, as an alternate sampling procedure authorized by permit, a sulfur analyses of the as-fired fuel oils and gaseous fuels while compliance testing for particulate matter and visible emissions. See specific conditions **A.10., A.11. and A.24.**

b. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

c. For monitoring purposes and in lieu of fuel sampling and analysis, the permittee shall operate an SO₂ CEMs. A RATA shall be conducted at least annually in accordance with 40 CFR 75.

[Rules 62-213.440, 62-296.405(1)(e)3. & 5., 62-296.405(1)(f)1.b. and 62-297.401, F.A.C.; Part V, Rule 2.501, JEPB; Part X, Rule 2.1001, JEPB; Part XI, Rule 2.1101, JEPB; and, AO16-194743, AO16-178094 and AO16-207528]

A.24. For Boilers Nos. 1 and 3, the following fuel sampling and analysis protocol shall be used if the permittee opts to demonstrate compliance with the sulfur dioxide standard using an alternate sampling procedure authorized by permit and conducted while performing a compliance test for particulate matter and visible emissions:

- a. Determine and record the as-fired fuel sulfur content, percent by weight, (1) for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, to analyze a representative sample of the blended fuel oil following each fuel delivery, (2) for gaseous fuels using ASTM D 1072-80, or the latest edition (the permittee can default to the maximum sulfur content guaranteed by the supplier).
- b. Record hourly fuel totalizer readings with calculated hourly feed rates for each fuel fired, the ratio of fuel oil to gas if co-fired, the density of each fuel, and the percent sulfur content, by weight, of each fuel.
- c. The analyses of the No. 6 fuel oil, as received from the supplier, shall include the following:
 - (1). Density (ASTM D 1298-80 or the latest edition).
 - (2). Calorific heat value in Btu per pound (ASTM D 240-76 or the latest edition).
- d. The analyses of the gaseous fuels, as received from the supplier, shall include the following:
 - (1). Density (ASTM D1137-53, ASTM D1945-64, or the latest edition).
 - (2). Calorific heat value in Btu per cubic foot (ASTM D1137-53, ASTM D1945-64, ASTM D1826-77, or the latest edition).
- e. Utilize the above information in a., b., c. and d. to calculate the SO₂ emission rate.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.; AO16-194743, AO16-178094 and AO16-207528; and, 40 CFR 60. Appendix A]

A.25. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.

[Rule 62-297.310(1), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.26. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

[Rules 62-297.310(2) & (2)(b), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.27. Operating Conditions During Testing - Particulate Matter and Visible Emissions.

Compliance tests for particulate matter and visible emissions during soot blowing and steady-state (non-soot blowing) operations shall be conducted at least once, annually, if liquid fuel is fired for more than 400 hours. All visible emissions tests shall be conducted concurrently with the particulate matter emissions tests. Testing shall be conducted as follows:

a. 100% Fuel Oil Firing.: Particulate matter and visible emissions tests during soot blowing and steady-state operations shall be performed on each emissions unit while firing fuel oil containing a sulfur content equal to or less than 1.8%, by weight, except that such test shall not be required to be performed during any federal fiscal year that testing is performed in accordance with specific condition **A.27.b.**

b. Co-firing Fuel Oil with Gases.: If fuel oil containing a sulfur content greater than 1.8%, by weight, is co-fired with gases (i.e., natural gas, landfill gas, LP gas), then particulate matter and visible emissions tests during soot blowing and steady-state operations shall be performed as soon as practicable, but in no event more than 60 days from the day of first firing the higher percent sulfur fuel oil, while co-firing such fuel oil with the proportion of gas required to maintain SO₂ emissions between 90 to 100% of the SO₂ emissions limitation (1.62 to 1.98 lbs/MMBtu heat input, respectively). Following successful completion of such particulate matter and visible emissions testing, further particulate matter and visible emissions testing shall not be required during the remaining federal fiscal year unless fuel oil is fired containing a sulfur content greater than 0.20%, by weight, above the fuel oil sulfur content percent, by weight, that was fired during the most recent co-firing compliance tests. If fuel oil is co-fired containing a sulfur content greater than 0.20%, by weight, above the fuel oil sulfur content percent, by weight, that was fired during the most recent co-firing compliance tests for particulate matter and visible emissions, then additional particulate matter and visible emissions tests shall be performed as described above and as soon as practicable, but in no event more than 60 days from the day of first firing the higher sulfur percent fuel oil. Following successful completion of such particulate matter and visible emissions testing, further particulate matter and visible emissions testing shall not be required during the remaining federal fiscal year unless fuel oil is fired containing a sulfur content greater than 0.20%, by weight, above the fuel oil sulfur content percent, by weight, that was fired during the most recent co-firing compliance tests. If any additional particulate matter and visible emissions tests are imposed after completion of any required annual compliance tests, then the frequency testing base date shall be reset to 12-months after the date of completion of the last tests.

[Rules 62-4.070(3), 62-213.440, 62-296.405(1)(c)3. and 62-297.310(7)(a)9., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.28. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.

[Rule 62-297.310(3), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.29. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1 (attached).

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube. [Rule 62-297.310(4), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.30. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit, and Part XI, Rule 2.1101, JEPB. [Rule 62-297.310(6), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.31. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal (see specific condition A.33.):

a. Did not operate; or

- b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
 - 4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
 - a. Visible emissions, if there is an applicable standard (see specific condition **A.32.**);
 - b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant(see specific condition **A.33.**); and,
 - c. Each NESHAP pollutant, if there is an applicable emission standard.
 - 5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid fuel, other than during startup, for a total of more than 400 hours. (see specific condition **A.33.**)
 - 9. The owner or operator shall notify the AWQD, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
- (b) Special Compliance Tests. When the AWQD, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the AWQD.
- (c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; Part XI, Rule 2.1101, JEPB; AO16-194743, AO16-178094 and AO16-207528; and, SIP approved]

A.32. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning (see specific condition **A.31.(a).4.a.**):

- a. only gaseous fuel(s); or
- b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
- c. only liquid fuel(s) for less than 400 hours per year.

[Rule 62-297.310(7)(a)4., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.33. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning (see specific conditions **A.31.(a)3., 4.b. & 5.**):

- a. only gaseous fuel(s); or
- b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
- c. only liquid fuel(s) for less than 400 hours per year.

[Rules 62-297.310(7)(a)3. & 5., F.A.C.; Part XI, Rule 2.1101, JEPB; and, ASP Number 97-B-01.]

A.34. Compliance with the “on-specification” used oil requirements will be determined from a sample collected from each batch delivered for firing. See specific conditions **A.13., A.38. and A.39.**

[Rules 62-4.070 and 62-213.440; and, 40 CFR 279]

Record keeping and Reporting Requirements

A.35. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the AWQD.

[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

A.36. For each calendar quarter, submit to the AWQD a written report of emissions in excess of emission limiting standards, as set forth in Rule 62-296.405(1), F.A.C., and any continuous emissions monitoring system outages. The nature and cause of the excess emissions shall be explained. The report shall be submitted within 30 calendar days following the last day of the quarterly period. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years. [Rules 62-213.440 and 62-296.405(1)(g), F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-207528]

A.37. Test Reports.

- (a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.
- (b) The required test report shall be filed with the AWQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.
- (c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the AWQD to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
 - 1. The type, location, and designation of the emissions unit tested.
 - 2. The facility at which the emissions unit is located.
 - 3. The owner or operator of the emissions unit.
 - 4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
 - 5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.; Part XI, Rule 2.1101, JEPB; and, AO16-214193, AO16-214194 and AO16-214195]

A.38. Records shall be kept of each delivery of “on-specification” used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of “on-specification” used oil fired in these emissions units. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See specific conditions **A.13.**, **A.34.** and **A.39.**

[Rule 62-213.440(1)(b)2.b., F.A.C.; and, 40 CFR 279.61 and 761.20(e)]

A.39. The permittee shall include in the “Annual Operating Report for Air Pollutant Emitting Facility” a summary of the “on-specification” used oil analyses for the calendar year and a statement of the total quantity of “on-specification” used oil fired in Boilers Nos. 1 and 3 during the calendar year. See specific conditions **A.13.**, **A.34.** and **A.38.**

[Rule 62-213.440(1)(b)2.b., F.A.C.]

A.40. When any of the NGS boilers, Nos. 1, 2 and 3, are shut down, it shall be recorded in the boiler's operating log book.

[Rule 62-213.440, F.A.C.; and, AC16-85951]

A.41. When electrical power demand requires all three main NGS boilers to be on line, the total station residual (No. 6) fuel oil consumption shall be recorded for each four-hour period whenever the NGS auxiliary steam generator (boiler) is operating. The recorded fuel consumption data shall be retained for at least five (5) years.

[Rule 62-213.440, F.A.C.; and, AC16-85951]

A.42. Fuel Consumption Records. The owner or operator shall create and maintain for each emissions unit hourly records of the amount of each fuel fired, the ratio of fuel oil to gas if co-fired, and the heating value and sulfur content, percent by weight, of each fuel fired. These records must be of sufficient detail to be able to identify when additional particulate matter and visible emissions testing is required pursuant to specific condition **A.27.b.**, and, when applicable, demonstrate compliance with the requirements of specific condition **A.24.e.**

[Rules 62-4.070(3), 62-213.410, 62-213.440 and 62-296.405(1)(c)3., F.A.C.]

Miscellaneous

A.43. For Boilers Nos. 1, 2 and 3, an Operation and Maintenance Plan is attached and a part of this permit pursuant to Rule 62-296.700(6), F.A.C. All activities shall be performed as scheduled and recorded data made available to the AWQD upon request. Records shall be maintained on file for a minimum of five (5) years.

[Rule 62-296.700(6), F.A.C.; and, Part X, Rule 2.1001, JEPB]

Section III. Emissions Units.

Subsection B. This section addresses the following emissions unit.

<u>E.U. ID No.</u>	<u>Brief Description</u>
-014	Northside Generating Station (NGS) Auxiliary Boiler No. 1

The NGS Auxiliary Boiler No. 1 is steam generator that is allowed to fire natural gas, LP gas, new No. 2 distillate or new No. 6 residual fuel oils, and a blend of new fuel oil(s) with internally generated waste oil that does not contain any polychlorinated biphenyls (PCBs). The maximum fuel oil sulfur content is 1.8%, by weight (BACT dated October 15, 1984). Emissions from this boiler are uncontrolled. The NGS Auxiliary Boiler No. 1 was authorized construction on October 15, 1984. This emissions unit can only be operated when one of the main NGS boilers (No. 1, 2 or 3) is either shut down or is in the startup mode of operation prior to being on line *or* when electrical power demand requires that all three main boilers (NGS Nos. 1, 2 and 3) and the auxiliary boiler (NGS No. 1) to be on line.

{Permitting note(s): The emissions unit is regulated under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 million Btu per Hour Heat Input, which includes BACT (dated October 15, 1984).}

The following specific conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rate is as follows:

<u>Unit No.</u>	<u>MMBtu/hr Heat Input</u>	<u>Fuel Type</u>
Aux. Boiler No. 1	123.5	Natural Gas
	123.5	LP Gas
	118.0	New No. 2 Fuel Oil
	116.5	New No. 6 Fuel Oil
	116.5-118.0	New Fuel Oil and On-site Generated Waste Oil

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

[AC16-85951; and, application received June 14, 1996.]

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **B.16.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation - Fuels.

- a. The only fuels allowed to be fired are natural gas, LP gas, new No. 2 distillate or new No. 6 residual fuel oils, or a blend of new fuel oil(s) with “internally generated waste oil”. The “internally generated waste oil” includes “on-specification” used oil, and excludes any PCB containing material from being fired in this emissions unit.
- b. The total station (NGS’s Boilers Nos. 1, 2 and 3, and Auxiliary Boiler No. 1) residual (No. 6) fuel oil consumption must not exceed 1,440,000 pounds in any consecutive three (3) hour period. [Rule 62-213.410, F.A.C.; and, AC16-85951 and BACT]

B.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8760 hours/year, but only when at least one of the main steam generating boilers (NGS Boiler No. 1, 2, or 3) is either shut down or in the startup mode of operation prior to being on line *or* when electrical power demand requires that all three main boilers (NGS Nos. 1, 2 and 3) and the auxiliary boiler (NGS No. 1) be on line. See specific conditions **B.3.b.**, **B.24.** and **B.25.**
[AC16-85951]

Emission Limitations and Standards

{Permitting Note: The attached Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.5. Visible Emissions. Visible emissions shall not exceed 15 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent.
[AC16-85951 and BACT]

B.6. Particulate Matter. Particulate matter emissions shall be controlled by the firing of natural gas and/or low sulfur content liquid fuel oil.
[Rule 62-296.406(2), F.A.C.; Part X, Rule 2.1001, JEPB; and, BACT]

B.7. Sulfur Dioxide - Sulfur Content. The maximum sulfur content of the new No. 2 distillate fuel oil, new No. 6 residual fuel oil, or blended fuel oil is 1.8 percent, by weight. See specific conditions **B.14.** and **B.15.**
[Rule 62-296.406(3), F.A.C.; and, AC16-85951 and BACT]

B.8. Internally Generated Waste Oil” (“On-specification” Used Oil). The burning of “internally generated waste oil”, which includes “on-specification” used oil, is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:
a. “Internally generated waste oil” is defined as: 1) automotive waste oils consisting of crankcase drainage, transmission fluids, gear lubricants, hydraulic oils, and minor amounts of kerosene and other solvents used in servicing equipment; 2) industrial waste oils used in metal working, lubrication of industrial equipment, hydraulic and circulating systems, diesel engines and turbine lubrication; and, 3) waste oils which have been used in transformers and heat transfer equipment that does not contain any PCBs.

b. "On-specification" used oil is defined as each used oil delivery that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below, except for PCBs. By permit, no (0.00%, by weight) PCBs are not allowed to be fired in this emissions unit. Used oil that does not meet all of the following specifications (normally, PCBs are limited to "less than 50 ppm") is considered "off-specification" used oil and shall not be fired in this emissions unit. See specific conditions **B.20.**, **B.26.** and **B.27.**

<u>CONSTITUENT / PROPERTY*</u>	<u>ALLOWABLE LEVEL</u>
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash Point	100 °F minimum
PCBs	none

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

[Rule 62-213.440, F.A.C.; AC16-85951 and BACT; and, 40 CFR 279.11]

Excess Emissions

B.9. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

B.10. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

[Rule 62-210.700(4), F.A.C.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

B.11. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

Test Methods and Procedures

{Permitting Note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.12. Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. See specific condition **B.13**.
[Rules 62-213.440 and 62-297.401, F.A.C.; Part XI, Rule 2.1101, JEPB; and, AC16-85951]

B.13. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

- a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
- b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

[Rule 62-297.401, F.A.C.; and, Part XI, Rule 2.1101, JEPB]

B.14. Sulfur Dioxide - Sulfur Content. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by the vendor providing a fuel analysis upon each fuel delivery. See specific conditions **B.7**. and **B.15**.
[Rules 62-213.440 and 62-296.406(3), F.A.C.; and, AC16-85951]

B.15. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition. See specific conditions **B.7**. and **B.14**.

[Rules 62-213.440, 62-296.406(3) and 62-297.440, F.A.C.; and, AC16-85951]

B.16. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

[Rules 62-297.310(2) & (2)(b), F.A.C.; Part XI, Rule 2.1101, JEPB; and, AC16-85951]

B.17. Applicable Test Procedures.

(a) Required Sampling Time.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2.c., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

B.18. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

- a. Visible emissions, if there is an applicable standard (see specific condition **B.19.**);
- b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and,
- c. Each NESHAP pollutant, if there is an applicable emission standard.

9. The owner or operator shall notify the AWQD, at least 14 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the AWQD, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; Part XI, Rule 2.1101, JEPB; AC16-85951; and, SIP approved]

B.19. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning (see specific condition **B.18.(a)4.a.**):

- a. only gaseous fuel(s); or
- b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
- c. only liquid fuel(s) for less than 400 hours per year.

[Rule 62-297.310(7)(a)4., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

B.20. Compliance with the “internally generated waste oil” - “on-specification” used oil requirements will be determined from a sample collected from each batch delivered for firing. See specific conditions **B.8.**, **B.26.** and **B.27.**

[Rules 62-4.070 and 62-213.440, F.A.C; and, 40 CFR 279]

Record keeping and Reporting Requirements

B.21. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the AWQD.
[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

B.22. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.

(b) The required test report shall be filed with the AWQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.

[Rule 62-297.310(8), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

B.23. The permittee shall submit all fuel oil analyses (every fuel oil delivery needs a fuel analysis report) and the visible emissions test, if one is required, to the AWQD annually. If fuel oil is being fired during a visible emissions test, then a sample of fuel oil shall be extracted during the test and analyzed; and, the analysis shall be submitted with the visible emissions test result to AWQD pursuant to Rule 62-297.310(8), F.A.C. See specific condition **B.22.**
[AC16-85951]

B.24. When any of the NGS boilers, Nos. 1, 2 and 3, are shut down, it shall be recorded in the boiler's operating log book.

[Rule 62-213.440, F.A.C.; and, AC16-85951]

B.25. When electrical power demand requires all three main NGS boilers to be on line, the total station residual (No. 6) fuel oil consumption shall be recorded for each four-hour period whenever the NGS auxiliary steam generator (boiler) is operating. The recorded fuel consumption data shall be retained for at least five (5) years.

[Rule 62-213.440, F.A.C.; and, AC16-85951]

B.26. Records shall be kept of each delivery of "internally generated waste oil" - "on-specification" used oil with a statement of the origin of the waste/used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "internally generated waste oil" - "on-specification" used oil fired in this emissions unit. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See specific conditions **B.8.**, **B.20.** and **B.27.**

[Rule 62-213.440, F.A.C.; AC16-85951; and, 40 CFR 279.61 and 761.20(e)]

B.27. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "internally generated waste oil" - "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in the (NGS) auxiliary boiler during the calendar year. See specific conditions **B.8.**, **B.20.** and **B.26.**

[Rule 62-213.440(1)(b)2.b., F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection C. This section addresses the following emissions units.

<u>E.U. ID No.</u>	<u>Brief Description</u>
-006	Combustion Turbine No. 3
-007	Combustion Turbine No. 4
-008	Combustion Turbine No. 5
-009	Combustion Turbine No. 6

Emissions units numbers 003, 004, 005 and 006 are combustion turbines (CTs) manufactured by General Electric (Model MS 7000) and are designated as CTs No. 3, No. 4, No. 5 and No. 6, respectively. Each CT has a maximum heat input from new No. 2 distillate fuel oil of 901.0 MMBtu (LHV: lower heating value). The No. 2 fuel oil has a maximum sulfur content of 0.5%, by weight. These CTs are used as peaking units during peak demand times, during emergencies, and during controls testing, to run a nominal 56.2 MW generator (each). Emissions from the CTs are uncontrolled. A group of exhaust stacks serve the CTs. CT No. 3 began commercial service in February 1975, No. 4 in January 1975, No. 5 in February 1974, and No. 6 in December 1974

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These emissions units are not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines.}

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity. The maximum operation heat input rates are as follows:

<u>Unit No.</u>	<u>MMBtu/hr Heat Input</u>	<u>Fuel Type</u>
3	901.0 (LHV)	New No. 2 Fuel Oil
4	901.0 (LHV)	New No. 2 Fuel Oil
5	901.0 (LHV)	New No. 2 Fuel Oil
6	901.0 (LHV)	New No. 2 Fuel Oil

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AO16-173886]

C.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition C.13.
[Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation - Fuels. Only new No. 2 distillate fuel oil shall be fired in the combustion turbines.
[Rule 62-213.410(1), F.A.C.; and, AO16-173886]

C.4. Hours of Operation. These emissions unit(s) may operate continuously, i.e., 8,760 hours/year.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AO16-173886]

Emission Limitations and Standards

{Permitting Note: The attached Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit. }

C.5. Visible Emissions. Visible emissions from each combustion turbine shall not be equal to or greater than 20 percent opacity.

[Rule 62-296.320(4)(b)1., F.A.C.; and, AO16-173886]

C.6. Sulfur Dioxide - Sulfur Content. The sulfur content of the new No. 2 distillate fuel oil shall not exceed 0.5 percent, by weight. See specific conditions C.9. and C.12.

[Requested in initial Title V permit application dated June 14, 1996; and, AO16-173886]

Excess Emissions

C.7. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

C.8. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

[Rule 62-210.700(4), F.A.C.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

C.9. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor upon each fuel delivery. See specific conditions C.6. and C.12.

[Rule 62-213.440, F.A.C.]

C.10. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

Test Methods and Procedures

{Permitting Note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.11. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.

[Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.; and, Part XI, Rule 2.1101, JEPB]

C.12. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition.

[Rules 62-213.440 and 62-297.440, F.A.C.; and, Part XI, Rule 2.1101, JEPB]

C.13. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

{Permitting note: Attached (see "Attachment NGS: CT Heat Input Nominal Values") is a chart of the "Base Load MW" vs "Temperature" to aid in defining "full load" for visible emissions testing purposes, since the manufacturer's curves are not available. The heat input numbers are only nominal values.}

[Rules 62-297.310(2), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

C.14. Applicable Test Procedures.

(a) Required Sampling Time.

2. Opacity Compliance Tests. When EPA Method 9 is specified as the applicable opacity test method, the required *minimum* period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur.

Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2.c., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

C.15. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard (see specific condition C.16.);

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit. (see specific condition C.16.)

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

C.16. Visible Emissions Testing - Biennial. By this permit, biennial (odd years) emissions compliance testing for visible emissions is required for each emissions unit, but is not required for those emissions units burning No. 2 fuel oil for less than 400 hours during the previous even year or the current odd year in question. (see specific conditions **C.15.(a)4.a. & 8.**)
[Rules 62-297.310(7)(a)4. & 8., F.A.C.; Part XI, Rule 2.1101, JEPB; and, AO16-173880]

Recordkeeping and Reporting Requirements

C.17. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the AWQD.

[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

C.18. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.

(b) The required test report shall be filed with the AWQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.

[Rule 62-297.310(8), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

C.19. Records of No. 2 fuel oil consumption shall be maintained and made available to AWQD upon request.

[Rule 62-213.440, F.A.C.; and, AO16-173886]

Section III. Emissions Unit(s) and Conditions.

Subsection D. This section addresses the following emissions units.

E.U.

<u>ID No.</u>	<u>Brief Description</u>
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2

SJRPP Boilers Nos. 1 and 2 are fossil fuel-fired steam generators, each having a nominal nameplate rating of 679.6 megawatts (electric). The emissions units will be allowed to fire pulverized coal, a blend of petroleum coke and coal, new No. 2 distillate fuel oil (startup and low-load operation), and "on-specification" used oil. The maximum heat input to each emissions unit is 6,144 million Btu per hour. SJRPP Boilers Nos. 1 and 2 are dry bottom wall-fired boilers and will use an electrostatic precipitator (ESP) to control particulate matter, a wet limestone flue gas desulfurization (FGD) unit to control sulfur dioxide, low NO_x burners and low excess-air firing to control nitrogen oxides, and good combustion to control carbon monoxide. Each boiler exhausts through its own stack (640 feet above grade). SJRPP Boiler No. 1 began commercial operation in December 1986. SJRPP Boiler No. 2 began commercial operation in March 1988.

{Permitting note(s): The emissions units are regulated under Acid Rain, Phase II and Phase I; NSPS - 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration [PSD; PSD-FL-010; PSD-FL-010(A & B)]; and, Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated May 7, 1981.}

The following specific conditions apply to the emissions unit(s) listed above:

{Permitting note: In addition to the requirements below, these emissions units are also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).}

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum operation heat input rate is as follows:

<u>Emissions Unit No.</u>	<u>MMBtu/hr Heat Input</u>
-016	6,144
-017	6,144

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; PSD-FL-010; Part III, Rule 2.301, JEPB; and, PA 81-13]

D.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **D.46.**
[Rule 62-297.310(2), F.A.C.; and, Part XI, Rule 2.1001, JEPB]

D.3. Methods of Operation.

- a. The only fuels allowed to be fired are coal, a coal blend with a maximum of 20 percent petroleum coke (by weight), new No. 2 distillate fuel oil, and “on-specification” used oil.
 - b. The new No. 2 fuel oil shall be used for startup and low load operation.
 - c. The maximum weight of petroleum coke burned shall not exceed 100,000 pounds per hour.
 - d. “On-specification” used oil will be generally fired as a blend with the No. 2 fuel oil. “On-specification” used oil containing PCBs above the detectable level of 2 ppm shall not be used for startup or shutdown. “On-specification” used oil containing PCBs between 2 and 49 ppm can only be fired when the emissions unit is at normal operating temperatures.
 - e. Either coal, a blend of coal and petroleum coke, or fuel oil shall not be fired in the emissions units unless both electrostatic precipitator and limestone scrubber are operating properly except as provided under 40 CFR 60, Subpart Da.
 - f. No fraction of the flue gas shall be allowed to bypass the limestone flue gas desulfurization (FGD) system to reheat the gasses exiting from the FGD system, if the bypass will cause overall SO₂ removal efficiency less than 90 percent or as otherwise provided in 40 CFR 60, Subpart Da. The percentage and amount of flue gas bypassing the FGD system shall be documented.
 - g. The permittee shall not operate its Southside, Northside, or Kennedy Generating Station in such a manner as to cause violation of ambient air quality standards for SO₂ when SJRPP is operating.
- [Rule 62-213.410, F.A.C.; PSD-FL-010; PA 81-13; PSD-FL-010(A & B); 40 CFR 761.20(e); and, requested by the applicant in the initial Title V permit application received June 14, 1996]

D.4. Hours of Operation. These emissions units are allowed to operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; Part III, Rule 2.301, JEPB; PSD-FL-010; and, PA 81-13]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.5. Revised Table 6, PSD-FL-010, is incorporated by reference (attached) for emissions units 1 and 2.

D.6. Particulate Matter. No owner or operator shall cause to be discharged into the atmosphere from any emissions unit any gases which contain particulate matter in excess of:

- (1) 0.03 lb/million Btu heat input derived from the combustion of solid or liquid fuels (coal, a blend of coal and petroleum coke, or fuel oil);
- (2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel (coal or a blend of coal and petroleum coke), and
- (3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(4) Particulate matter emissions shall be controlled with an electrostatic precipitator.
[40 CFR 60.42a(a)(1), (2) & (3); PSD-FL-010 and BACT; PA 81-13; and, PSD-FL-010(A & B)]

D.7. Ash Content.

- a. The maximum ash content of the coal is 18%, by weight.
 - b. The maximum ash content of the No. 2 fuel oil is 0.01%, by weight.
- [PSD-FL-010; and, PA 81-13]

D.8. Visible Emissions. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6 minute average), except for one 6-minute period per hour of not more than 27 percent opacity.
[40 CFR 60.42a(b); and, PA 81-13]

D.9. Sulfur Dioxide - Coal Only. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel any gases which contain sulfur dioxide in excess of:
(1) 1.20 lb/million Btu heat input, maximum two-hour average, and 0.76 lb/MMBtu heat input (90% reduction of the potential combustion concentration), 30-day rolling average; or
(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 0.60 lb/million Btu heat input.
(3) 100 percent of the potential combustion concentration (zero percent reduction), when emissions are less than 0.20 lb/million Btu heat input.
(4) SO₂ emissions shall be controlled with a lime/limestone flue gas desulfurization system on each boiler.
[40 CFR 60.43a(a)(1), (2) & (3); PSD-FL-010 and BACT; and, PA 81-13]

D.10. Sulfur Dioxide - Coal and Petroleum Coke Blends.

- a. When coals with a sulfur content less than or equal to 2.00%, by weight, are co-fired with petroleum coke, the SO₂ emissions shall not exceed 0.55 lb/MMBtu heat input and a minimum of 76% reduction shall be achieved in the flue gas desulfurization system.
- b. When coals with a sulfur content between 2.00% and 3.63%, by weight, are co-fired with petroleum coke, the SO₂ emissions shall not exceed the following formula:

$$\text{SO}_2 \text{ (lb/MMBtu)} = (0.2 \times C/100) + 0.4$$

where: C = percent of coal co-fired on a heat input basis.

Please note: C is on a heat input basis and not on a weight input basis, so appropriate conversions should be used.

- c. When coals with a sulfur content greater than 3.63%, by weight, are co-fired with petroleum coke, the SO₂ emissions shall not exceed the following formula:

$$\text{SO}_2 \text{ (lb/MMBtu)} = (0.1653 \times C \times S - 0.4 \times C + 40) \times 1/100$$

where: C = percent of coal co-fired on a heat input basis; and,
S = weight percent sulfur in coal.

- d. The maximum SO₂ emissions rate when co-firing petroleum coke and coal shall not exceed 0.676 lb/MMBtu heat input.
- e. Compliance with the SO₂ emissions limit shall be based on a 30-day rolling average for those days when petroleum coke is fired. Any use of petroleum coke during a 24-hour period shall be considered 1 day of the 30-day rolling average. The 30-day rolling average shall be calculated according to the Standards of Performance for New Stationary Sources (NSPS) codified in 40 CFR 60, Subpart Da, except as noted above.
- [PSD-FL-010(A & B)]

D.11. Sulfur Dioxide - Liquid Fuel Only. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility which combusts liquid fuel any gases which contain sulfur dioxide in excess of:

- (1) 340 ng/J (0.80 lb/million Btu) heat input and 90 percent reduction, or
- (2) 100 percent of the potential combustion concentration (zero percent reduction), when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

[40 CFR 60.43a(b)(1) & (2)]

D.12. Sulfur Dioxide. Compliance with the emission limitation and percent reduction requirements are both determined on a 30-day rolling average basis.

[40 CFR 60.43a(g); PSD-FL-010; and, PA 81-13]

D.13. Sulfur Dioxide - Sulfur Content. (see specific condition **D.74**.)

- a. The maximum coal sulfur content shall not exceed 4.0 percent, by weight.
- b. The maximum sulfur content of the coal - petroleum coke blend shall not exceed 4.0 percent, by weight.
- c. The maximum sulfur content of the No. 2 fuel oil is 0.76%, by weight.

[PSD-FL-010; PA 81-13; and, PSD-FL-010(A & B)]

D.14. Sulfur Dioxide. When fuel oil and coal (or a blend of coal and petroleum coke) are combusted simultaneously, the applicable standard is determined by proration using the following formulas:

(1) If emissions of SO₂ to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input:

$$PS_{SO_2} = (340X + 520Y)/100 \text{ and}$$
$$\%P_S = 10$$

(2) If emissions of SO₂ to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:

$$PS_{SO_2} = (340X + 520Y)/100 \text{ and}$$
$$\%P_S = (10X + 30Y)/100$$

where:

PS_{SO₂} = the prorated standard for sulfur dioxide when combusting fuel oil and coal (or a blend of coal and petroleum coke) simultaneously (ng/J heat input).

%P_S = percentage of potential SO₂ emissions allowed.

X = the percentage of total heat input derived from the combustion of fuel oil (excluding solid-derived fuels).

Y = the percentage of total heat input derived from the combustion of coal or a blend of coal and petroleum coke (including solid-derived fuels).

[40 CFR 60.43a(h)(1) & (2)]

D.15. Nitrogen Oxides. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.

(1) NO_x emissions limits.

a. Coal or coal-petroleum coke blend: 0.60 lb/million Btu (260 ng/J) heat input;

b. Fuel oil: 130 ng/J (0.30 lb/million Btu) heat input.

(2) NO_x reduction requirement.

a. Solid fuels: 65 percent reduction of potential combustion concentration;

b. Liquid fuels: 30 percent reduction of potential combustion concentration.

[40 CFR 60.44a(a)(1) & (2)]

D.16. Nitrogen Oxides. When fuel oil and coal (or a blend of coal and petroleum coke) are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$PS_{NOX} = (130X + 260Y)/100$$

where:

PS_{NOX} is the prorated standard for nitrogen oxides when combusting coal (or a blend of coal and petroleum coke) and fuel oil simultaneously (ng/J heat input).

X = the percentage of total heat input derived from the combustion of fuel oil.

Y = the percentage of total heat input derived from the combustion of coal or a blend of coal and petroleum coke.

[40 CFR 60.44a(c); and, PSD-FL-010]

D.17. “On-Specification” Used Oil. The burning of “on-specification” used oil is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:

a. Only “on-specification” used oil generated by the Jacksonville Electric Authority in the production and distribution of electricity shall be fired in these emissions units. The total combined quantity allowed to be fired in these emissions units shall not exceed 1,000,000 gallons per calendar year. “On-specification” used oil is defined as each used oil delivery that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered “off-specification” oil and shall not be fired. See specific conditions **D.44.**, **D.63.**, **D.64.** and **D.66.**

<u>CONSTITUENT / PROPERTY*</u>	<u>ALLOWABLE LEVEL</u>
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash Point	100 °F minimum
PCBs	less than 50 ppm

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).
[40 CFR 279.11]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of an NSPS, NESHAP, or Acid Rain program provision.}

D.18. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. See Attachment SJRPP: Protocol for Startup and Shutdown.

[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

{Permitting note: Once a written agreement between JEA and AWQD has been acquired approving a “Protocol for Startup and Shutdown”, the protocol is automatically incorporated by reference and is a part of the permit. The protocol shall be used where applicable and where there is/are conflict with the rule.}

D.19. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.

[Rule 62-210.700(4), F.A.C.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

D.20. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.; and, Part XI, Rule 2.1001, JEPB]

Compliance Provisions

D.21. Compliance with the particulate matter emission limitation under 40 CFR 60.42a(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under 40 CFR 60.42a(a)(2) and (3).

[40 CFR 60.46a(a)]

D.22. Compliance with the nitrogen oxides emission limitation under 40 CFR 60.44a(a)(1) constitutes compliance with the percent reduction requirements under 40 CFR 60.44a(a)(2).

[40 CFR 60.46a(b)]

D.23. The particulate matter emission standards under 40 CFR 60.42a and the nitrogen oxide standards under 40 CFR 60.44a apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under 40 CFR 60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under 40 CFR 60.46a(d) are implemented.

[40 CFR 60.46a(c)]

D.24. During emergency conditions in the principle company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

- (1) Operating all operable flue gas desulfurization modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,
- (2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation.

[40 CFR 60.46a(d)(1) & (2)]

D.25. Compliance with the sulfur dioxide emission limitations and the percentage reduction requirements under 40 CFR 60.43a and the nitrogen oxides emissions limitations under 40 CFR 60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

[40 CFR 60.46a(e)]

D.26. Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO₂ and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (NO_x only), or emergency conditions (SO₂ only). Compliance with the percentage reduction requirement for SO₂ is determined based on the average inlet and average outlet SO₂ emissions rates for the 30 successive boiler operating days.

[40 CFR 60.46a(g)]

D.27. If the owner or operator has not obtained the minimum quantity of emission data as required under 40 CFR 60.47a, compliance of the affected facility with the emission requirements under 40 CFR 60.43a and 60.44a for the day on which the 30-day period ends may be determined by the Administrator following the applicable procedures in section 7 of Method 19.

[40 CFR 60.46a(h)]

Continuous Monitoring Requirements

D.28. Opacity. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharges to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

[40 CFR 60.47a(a)]

D.29. Sulfur Dioxide. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

[40 CFR 60.47a(b)(1)]

D.30. Nitrogen Oxides. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

[40 CFR 60.47a(c)]

D.31. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

[40 CFR 60.47a(d)]

D.32. The continuous monitoring systems are operated and data recorded during all periods of operation at the affected facility including periods of startup, shutdown, malfunction, or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

[40 CFR 60.47a(e)]

D.33. The owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in 40 CFR 60.47a(h).

[40 CFR 60.47a(f)]

D.34. The 1-hour averages required under 40 CFR 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under 40 CFR 60.46a. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b). At least two data points must be used to calculate the 1-hour averages.

[40 CFR 60.47a(g)]

D.35. When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in 40 CFR 60.47a(f), the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods are given in 40 CFR 60.47a(j).

(1) Method 6 shall be used to determine the SO₂ concentration at the same location as the SO₂ monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 shall be used to determine the NO_x concentration at the same location as the NO_x monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O₂ or CO₂ concentration at the same location as the O₂ or CO₂ monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (lb/million Btu) heat input.

[40 CFR 60.47a(h)(1), (2), (3) & (4)]

D.36. The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d). Acceptable alternative methods and procedures are given in 40 CFR 60.47a(j). (1) Methods 6, 7, and 3B, as applicable, shall be used to determine O₂, SO₂, and NO_x concentrations.

(2) SO₂ or NO_x (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N₂, as applicable) under Performance Specification 2 of appendix B of 40 CFR 60.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides firing solid fuel is 1,000 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

[40 CFR 60.47a(i)(1), (2), (3), & (5)]

D.37. The owner or operator may use the following as alternatives to the reference methods and procedures specified in 40 CFR 60.47a.

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under 40 CFR 60.47a(i), the conditions under 40 CFR 60.46(d)(1) apply (see specific condition **D.73.**); these conditions do not apply under 40 CFR 60.47a(h).

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time is 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

[40 CFR 60.47a(j)]

Test Methods and Procedures

{Permitting note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.38. In conducting performance tests, the owner or operator shall use as reference methods and procedures the methods in appendix A of 40 CFR 60 or the methods and procedures as specified in 40 CFR 60.48a, except as provided in 40 CFR 60.8(b). 40 CFR 60.8(f) does not apply to this section for SO₂ and NO_x. Acceptable alternative methods are given in 40 CFR 60.48a(e).

[40 CFR 60.48a(a)]

D.39. Particulate Matter. The owner or operator shall determine compliance with the particulate matter standard as follows

- (1) The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.
- (2) For the particulate matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.
 - (i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ± 14 °C (320 ± 25 °F).
 - (ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same transverse points as, the particulate run. If the particulate run has more than 12 transverse points, the O_2 transverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 transverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 concentrations at each transverse point.
- (3) Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.
[40 CFR 60.48a(b)(1), (2) & (3)]

D.40. Sulfur Dioxide. The owner or operator shall determine compliance with the sulfur dioxide standards as follows:

- (1) The percent of potential SO_2 emissions ($\%P_S$) to the atmosphere shall be computed using the following equation:

$$\%P_S = [(100 - \%R_F)(100 - \%R_S)]/100$$

where:

- $\%P_S$ = percent of potential SO_2 emissions, percent.
- $\%R_F$ = percent reduction from fuel pretreatment, percent.
- $\%R_S$ = percent reduction by SO_2 control system, percent.

- (2) The procedures in Method 19 may be used to determine percent reduction ($\%R_F$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.
- (3) The procedures in Method 19 shall be used to determine the percent SO_2 reduction ($\%R_S$) of any SO_2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 consecutive boiler operating days.
- (4) The appropriate procedures in Method 19 shall be used to determine the emission rate.
- (5) The continuous monitoring system in 40 CFR 60.47a(b) and (d) shall be used to determine the concentrations of SO_2 and CO_2 or O_2 .
[40 CFR 60.48a(c)(1), (2), (3), (4) & (5)]

D.41. Nitrogen Oxides. The owner or operator shall determine compliance with the NO_x standard as follows:

- (1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO_x.
- (2) The continuous monitoring system in 40 CFR 60.47a(c) and (d) shall be used to determine the concentrations of NO_x and CO₂ or O₂.
[40 CFR 60.48a(d)(1) & (2)]

D.42. The owner or operator may use the following as alternatives to the reference methods and procedures specified in 40 CFR 60.48a:

- (1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed the average temperature of 160 °C (320 °F). Procedures 2.1 and 2.3 of Method 5B in 40 CFR 60, Appendix A may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.
- (2) The F_C factor (CO₂) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of 40 CFR 60.46(d)(1). The CO₂ shall be determined in the same manner as the O₂ concentration.
[40 CFR 60.48a(e)(1) & (2)]

D.43. Compliance with the “on-specification” used oil requirements will be determined as follows:

- (a) Analysis of a sample collected from each batch delivered for firing; or,
 - (b) The new batch delivery is from a collection site that has an acceptable analysis already on file with the facility and the analytical results are assumed by the facility for the batch.
 - (c) For quantification purposes, the highest concentration of each constituent as determined by any analysis is assumed to be the concentration of the constituent of the blended used oil.
- See specific conditions **D.17.**, **D.64.**, **D.65.** and **D.66.**

[Rules 62-4.070 and 62-213.440(1)(b)2.b., F.A.C.; Part V, Rule 2.501, JEPB; and, 40 CFR 279]

D.44. If the permittee wants the CEMs RATA tests for SO₂ and NO_x to be considered as formal compliance tests, then the permittee must satisfy all of the requirements (i.e., prior notification, submittal requirements, etc.) of Rule 62-297.310, F.A.C.

[Rules 62-297.310(7) and 62-213.440, F.A.C.]

D.45. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may

accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.

[Rule 62-297.310(1), F.A.C.; and, Part XI, Rule 2.1001, JEPB]

D.46. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

[Rules 62-297.310(2) & (2)(b), F.A.C.; and, Part XI, Rule 2.1001, JEPB]

D.47. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.

[Rule 62-297.310(3), F.A.C.; and, Part XI, Rule 2.1001, JEPB]

D.48. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached as part of this permit.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube. [Rule 62-297.310(4), F.A.C.; and, Part XI, Rule 2.1001, JEPB]

D.49. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.

[Rule 62-297.310(6), F.A.C.; and, Part XI, Rule 2.1001, JEPB]

D.50. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

- a. Did not operate; or
- b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

- a. Visible emissions, if there is an applicable standard (see specific condition **D.51.**);
- b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant (see specific condition **D.51.**); and,
- c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours. (see specific condition **D.51.**)

9. The owner or operator shall notify the AWQD, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the AWQD, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the AWQD.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; Part XI, Rule 2.1101, JEPB; PA 81-13; and, SIP approved]

D.51. Stack tests for particulate matter, nitrogen oxides, sulfur dioxide, and visible emissions shall be performed annually. (see specific conditions **D.44., D.50.(a)4.a. & b. and 5.**)
[PA 81-13]

Record keeping and Reporting Requirements

D.52. For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

[40 CFR 60.49a(a)]

D.53. For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxides emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and, description of corrective actions taken.

- (5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO₂ only), or other reasons, and justification for excluding data other than startup, shutdown, malfunction, or emergency conditions.
- (6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
- (7) Identification of the times when hourly averages have been obtained based on manual sampling methods.
- (8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.
- (9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.
[40 CFR 60.49a(b)(1), (2), (3), (4), (5), (6), (7), (8) & (9)]

D.54. If the required quantity of emission data as required by 40 CFR 60.47a is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of 40 CFR 60.46a(h) is reported to the Administrator for that 30-day period:

- (1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.
- (2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.
- (3) The lower confidence limit for the mean outlet emission rate (E_o^*) and the upper confidence limit for the mean inlet emission rate (E_i^*) as applicable.
- (4) The applicable potential combustion concentration.
- (5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o^*) and the allowable emission rate (E_{std}) as applicable.

[40 CFR 60.49a(c)(1), (2), (3), (4) & (5)]

D.55. If any standards under 40 CFR 60.43a are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

- (1) Indicating if emergency conditions existed and requirements under 40 CFR 60.46a(d) were met during each period, and
- (2) Listing the following information:
 - (i) Time periods the emergency condition existed;
 - (ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;
 - (iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;
 - (iv) Percent reduction in emissions achieved;
 - (v) Atmospheric emission rate (ng/J) of the pollutant discharged; and
 - (vi) Actions taken to correct control system malfunction.

[40 CFR 60.49a(d)(1) & (2)]

D.56. If fuel pretreatment credit toward the sulfur dioxide emission standard under 40 CFR 60.43a is claimed, the owner or operator of the affected facility shall submit a signed statement:

- (1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of 40 CFR 60.48a and Method 19 (appendix A); and

- (2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

[40 CFR 60.49a(e)(1) & (2)]

D.57. For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and the affected facility during periods of data unavailability are to be compared with operation of the control system and the affected facility before and following the period of data unavailability.

[40 CFR 60.49a(f)]

D.58. The owner or operator of the affected facility shall submit a signed statement indicating whether:

- (1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

- (2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

- (3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

- (4) Compliance with the standards has or has not been achieved during the reporting period.

[40 CFR 60.49a(g)(1), (2), (3) & (4)]

D.59. For the purposes of the reports required under 40 CFR 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR 60.42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

[40 CFR 60.49a(h)]

D.60. The owner or operator of an affected facility shall submit the written reports required under 40 CFR 60.49a and 40 CFR 60, Subpart A, to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

[40 CFR 60.49a(i)]

D.61. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the AWQD.

[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

D.62. Test Reports.

- (a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.
- (b) The required test report shall be filed with the AWQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.
- (c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the AWQD to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
 1. The type, location, and designation of the emissions unit tested.
 2. The facility at which the emissions unit is located.
 3. The owner or operator of the emissions unit.
 4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
 5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
 6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
 7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
 8. The date, starting time and duration of each sampling run.
 9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
 10. The number of points sampled and configuration and location of the sampling plane.
 11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
 12. The type, manufacturer and configuration of the sampling equipment used.
 13. Data related to the required calibration of the test equipment.
 14. Data on the identification, processing and weights of all filters used.
 15. Data on the types and amounts of any chemical solutions used.
 16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
 17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
 18. All measured and calculated data required to be determined by each applicable test procedure for each run.
 19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
 20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.; Part XI, Rule 2.1101, JEPB]

D.63. Records shall be kept of each delivery of “on-specification” used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of “on-specification” used oil fired in these emissions units; or, hourly if fired unblended. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See specific conditions **D.17.**, **D.44.**, **D.64.** and **D.65.**

[Rule 62-213.440(1)(b)2.b., F.A.C.; Part V, Rule 2.501, JEPB; and, 40 CFR 279.61 and 761.20(e)]

D.64. The permittee shall include in the “Annual Operating Report (AOR) for Air Pollutant Emitting Facility” a summary of the “on-specification” used oil analyses for the calendar year and a statement of the total quantity of “on-specification” used oil fired in Boilers Nos. 1 and 2 and the auxiliary boilers during the calendar year. See specific conditions **D.17.**, **D.44.**, **D.63.** and **D.65.**

[Rule 62-213.440(1)(b)2.b., F.A.C.; and, Part V, Rule 2.501, JEPB]

D.65. Fuel Consumption Records. The owner or operator shall maintain, for each emissions unit, a daily log of the amounts and types of fuels fired and copies of fuel analyses containing information on the sulfur and ash content, percent by weight, and heating values. See specific conditions **D.17.**, **D.44.**, **D.63.** and **D.64.**

[Rule 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010 and PA 81-13]

D.66. Reporting and Recordkeeping. Documentation verifying that the coal and petroleum coke fuel blends combusted in Boilers Nos. 1 and 2 have not exceeded the 20 percent maximum petroleum coke by weight limit shall be maintained and made available upon request by the Department or AWQD.

[Rule 62-213.440, F.A.C.; and, Part V, Rule 2.501, JEPB]

D.67. Reporting and Recordkeeping. Stack monitoring, fuel usage and fuel analysis data shall be reported to the AWQD on a quarterly basis in accordance with 40 CFR 60.7.

[PA 81-13]

D.68. Nitrogen Oxides and Particulate Matter. The permittee shall maintain and submit to the Department and AWQD, on an annual basis for a period of five years from the date each emissions unit begins co-firing petroleum coke, data demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational change associated with the use of petroleum coke did not result in a significant emission increases of nitrogen oxides and particulate matter.

[Rule 62-213.440, F.A.C.; and, Part V, Rule 2.501, JEPB; and, PSD-FL-010(A) & (B)]

D.69. Carbon Monoxide. The permittee shall maintain and submit to the Department and AWQD, on a semiannual basis for a period of two years from the date each emissions unit begins co-firing petroleum coke, and then on an annual basis (if the first two years of data show no significant increase in carbon monoxide emissions) for an additional three years, information demonstrating that the operational changes did not result in a significant emissions increase of carbon monoxide. The carbon monoxide emissions shall be based on test results using EPA Method 10. Additionally, quarterly continuous emissions monitoring data for carbon monoxide emissions shall be submitted to the Department and AWQD for a period of two years to show the range of emissions experienced during each quarter.

[Rule 62-210.200(12)(d), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010(A) & (B)]

D.70. Sulfuric Acid Mist. The permittee shall maintain and submit to the Department and AWQD, on a semiannual basis for a period of two years from the date each emissions unit begins co-firing petroleum coke, information demonstrating that the operational changes did not result in a significant emissions increase of sulfuric acid mist. The sulfuric acid mist emissions shall be based on test results using EPA Method 8.

[Rule 62-210.200(12)(d), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010(A) & (B)]

Miscellaneous

D.71. Stack Height. The height of each boiler's exhaust stack for SJRPP Boiler No. 1 and No. 2 shall not be less than 640 feet above grade.

[PSD-FL-010 and PA 81-13]

D.72. The permittee shall comply with the requirements contained in Appendix 40 CFR 60, Subpart A, attached to this permit.

[Rule 62-204.800(7)(d), F.A.C.]

D.73. The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified:

(1) The emission rate (E) of particulate matter, SO₂ and NO_x may be determined by using the F_c factor, provided that the following procedure is used (see specific condition **D.42.**):

(i) The emission rate (E) shall be computed using the following equation:

$$E = C F_c (100 / \% \text{CO}_2)$$

where:

E = emission rate of pollutant, ng/J (lb/million Btu).

C = concentration of pollutant, ng/dscm (lb/dscf).

% CO₂ = carbon dioxide concentration, percent dry basis.

F_c = factor as determined in appropriate sections of Method 19.

(ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O_2 and CO_2 concentration according to the procedures in 40 CFR 60.46(b)(2)(ii), (4)(ii), or (5)(ii). Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., $F_{oa} = 0.209 (F_{da} / F_{ca})$, then the following procedure shall be followed:

(A) When F_o is less than $0.97 F_{oa}$, then E shall be increased by that proportion under $0.97 F_{oa}$, e.g., if F_o is $0.95 F_{oa}$, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than $0.97 F_{oa}$ and when the average difference (\bar{d}) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under $0.97 F_{oa}$, e.g., if F_o is $0.95 F_{oa}$, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than $1.03 F_{oa}$ and when \bar{d} is positive, then E shall be decreased by that proportion over $1.03 F_{oa}$, e.g., if F_o is $1.05 F_{oa}$, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

[40 CFR 60.46(d)(1)]

D.74. Fuel - Sulfur Content. (see specific condition D.13.)

a. Coal or Coal - Petroleum Coke Blend. The as-fired fuel sulfur content, percent by weight, for the coal or coal - petroleum coke blend shall be determined using ASTM D2013-72 and either ASTM D3177-75, ASTM D4239-85, ASTM D3176-74, or the latest edition, to analyze a representative sample of the fuel being fired; or, the operation of an inlet SO_2 analyzer with support provided from a vendor's supplied analysis for each shipment of fuel delivered shall be used to establish the sulfur content, percent by weight, of the fuel being fired.

b. No 2. Fuel Oil. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, ASTM D1552-95, both ASTM D4057-88 and ASTM D129-91, or the latest edition. The permittee shall have an as-fired sample analyzed after each fuel delivery or the vendor shall provide an analysis including sulfur content and heating value for each fuel delivery. However, if the No. 2 fuel oil being delivered has a sulfur content of 0.76 % or less, by weight, then the vendor's analysis is acceptable and no further analysis is required.

[Rules 62-213.440 and 62-297.440, F.A.C.; 40 CFR 60.17; and, 40 CFR 60.47a]

Section III. Emissions Unit(s) and Conditions.

Subsection E. This section addresses the following emissions unit(s).

E.U.

ID No. Brief Description

-023 SJRPP: Coal Storage Yard and Transfer Systems

The coal receiving, storage and transfer systems at the coal storage yard support the operation of the two power boilers. The emissions units/points are as depicted in Table 6 (Revised; and, PSD-FL-010) and the appropriate part of Attachment SJRPP: Material Handling Transfer Points. Particulate matter emissions are controlled using fabric filter systems, water sprays, wetting agents, and full enclosures or partial enclosures, where appropriate.

{Permitting notes: The emissions unit is regulated under NSPS - 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Prevention of Significant Deterioration (PSD): PSD-FL-010 dated March 12, 1982; Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated May 7, 1981; and, PPSA : PA 81-13 (revised 08/01/95).}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

E.1. Revised Tables 2 and 6, PSD-FL-010, are incorporated by reference (attached) for emissions units 1 thru 16 and 4 thru 17, respectively.

E.2. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.

[Rule 62-210.200(PTE), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010]

E.3. Controls. The permittee shall maintain and continue to use the control systems and control techniques established to minimize particulate matter emissions from emissions units 4 thru 17 in Revised Table 2, PSD-FL-010.

[Rules 62-4.070 and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; and, PSD-FL-010]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E.4. Visible Emissions. An owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, visible emissions greater than 10 percent opacity, as established in Revised Table 6, PSD-FL-010.

[PSD-FL-010, PA 81-13 and BACT]

E.5. Particulate Matter. Particulate matter emissions shall not exceed the limits established in Revised Table 6, PSD-FL-010.

[Rules 62-4.070 and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; and, PSD-FL-010]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of an NSPS, NESHAP, or Acid Rain program provision.}

E.6. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

E.7. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.

[Rule 62-210.700(4), F.A.C.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

E.8. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.; Part XI, Rule 2.1101, JEPB]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E.9. Visible Emissions. EPA Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity compliance pursuant to Chapter 62-297, F.A.C., and 40 CFR 60, Appendix A. If the opacity limits are not met for those emissions units that exhaust through a stack, permit compliance shall be determined on the basis of mass emission rate tests. See specific condition

E.10.

[40 CFR 60.252(c); and, PSD-FL-010 and PA 81-13]

E.10. Particulate Matter. In accordance with Chapter 62-297, F.A.C., EPA Method 5 shall be used to determine compliance with the particulate matter emission limitations established in Revised Table 6, PSD-FL-010, for emissions units 4 thru 17 that exhaust through a stack. If the opacity limits are not met for those emissions units that exhaust through a stack, permit compliance shall be determined on the basis of mass emission rate tests. See specific condition E.9.

[Rules 62-4.070 and 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010]

E.11. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

{Permitting note: The Revised Table 2 includes a summary of the various emissions points/ activities and their control systems for the Coal Storage Yard and Transfer Systems. The throughput rate amounts displayed represent approximately 74 percent of their maximum potential. Therefore, when any visible emissions test is being conducted, the emissions point/ activity being evaluated should be operating at or near its maximum potential throughput rate.}

[Rules 62-297.310(2) & (2)(b), 62-213.440(1) and 62-4.070(3), F.A.C.; Part XI, Rule 2.1101, JEPB]

E.12. Applicable Test Procedures.

(a) Required Sampling Time.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2.c., F.A.C.; Part XI, Rule 2.1101, JEPB]

E.13. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate;

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; Part XI, Rule 2.1101, JEPB; and, SIP approved]

Recordkeeping and Reporting Requirements

E.14. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the AWQD.

[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

E.15. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.

(b) The required test report shall be filed with the AWQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.

[Rule 62-297.310(8), F.A.C.; Part XI, Rule 2.1101, JEPB]

Miscellaneous Requirements.

E.16. The permittee shall comply with the requirements contained in Appendix 40 CFR 60, Subpart A, attached to this permit.

[Rule 62-204.800(7)(d), F.A.C.]

Section III. Emissions Units.

Subsection F. This section addresses the following emissions unit.

<u>E.U. ID No.</u>	<u>Brief Description</u>
-022	SJRPP: Limestone and Flyash Handling

Fugitive particulate matter emissions will be generated from limestone and flyash handling and storage systems. The emissions units/points are as depicted in Table 6 (Revised: PSD-FL-010) and the appropriate part of Attachment SJRPP: Material Handling Transfer Points. Various control strategies that will be used to minimize emissions are enclosures, wet suppression sprays, and control systems like baghouses. Visible emissions limits will be used to indicate compliance, with mass tests as backup requirements where visible emissions limits are violated.

{Permitting note(s): The emissions units are regulated under Rule 62-212.400(5), PSD NSR Review, which includes BACT (dated 05/07/81; PSD-FL-010 was issued March 12, 1982).}

The following specific conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

F.1. Revised Tables 2 and 6, PSD-FL-010, are incorporated by reference (attached) for emissions units 17 thru 18 and 18 thru 19, respectively.

F.2. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.

[Rule 62-210.200(PTE), F.A.C.; Part III, Rule 2.301, JEPB]

F.3. Controls. The permittee shall maintain and continue to use the control systems and control techniques established to minimize particulate matter emissions from emissions units 17 and 18 in Revised Table 2, PSD-FL-010.

[Rules 62-4.070 and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; and, PSD-FL-010]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

F.4. Visible Emissions. Visible emissions shall not exceed the following:

- | | |
|--|-------------|
| a. Limestone and flyash handling systems | 10% opacity |
| b. Limestone transfer points | 10% opacity |
| c. Limestone silo | 10% opacity |
| d. Limestone unloading (rail dumper) | 10% opacity |
| e. Flyash silos | 10% opacity |

[PSD-FL-010 and PA 81-13]

F.5. Particulate Matter. Particulate matter emissions shall not exceed the following:

- | | |
|--|------------|
| a. Limestone silo | 0.05 lb/hr |
| b. Limestone hopper/transfer conveyors | 0.65 lb/hr |
| c. Limestone transfer points | 0.4 lb/hr |
| d. Limestone unloading (rail dumper) | 0.1 lb/hr |
| e. Flyash handling system | 0.2 lb/hr |

[Rule 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; and, PSD-FL-010 and PA 81-13]

Excess Emissions

F.6. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

F.7. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.

[Rule 62-210.700(4), F.A.C.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

F.8. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

F.9. Visible Emissions. EPA Method 9 shall be used to determine opacity compliance pursuant to Chapter 62-297, F.A.C., and 40 CFR 60, Appendix A.

[Rule 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010 and PA 81-13]

F.10. Particulate Matter. In accordance with Chapter 62-297, F.A.C., EPA Method 5 shall be used to determine compliance with the particulate matter emission limitations established in Revised Table 6, PSD-FL-010, for emissions units 18 and 19 that exhaust through a stack. If the opacity limits are not met for those emissions units that exhaust through a stack, permit compliance shall be determined on the basis of mass emission rate tests.

[Rules 62-4.070 and 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010]

F.11. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

{Permitting note: The Revised Table 2 includes a summary of the various emissions points/ activities and their control systems for the Limestone and Flyash Handling. The throughput rate amounts displayed represent approximately 74 percent of their maximum potential. Therefore, when any visible emissions test is being conducted, the emissions point/ activity being evaluated should be operating at or near its maximum potential throughput rate.}

[Rules 62-297.310(2) & (2)(b), 62-213.440(1) and 62-4.070(3), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

F.12. Applicable Test Procedures.

(a) Required Sampling Time.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2.c., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

F.13. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate;

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the AWQD, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; and, Part XI, Rule 2.1101, JEPB and, SIP approved]

Recordkeeping and Reporting Requirements

F.14. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the AWQD.

[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

F.15. Test Reports.

- (a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.
- (b) The required test report shall be filed with the AWQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.

[Rule 62-297.310(8), F.A.C.]

Section III. Emissions Units.

Subsection G. This section addresses the following emissions unit.

<u>E.U. ID No.</u>	<u>Brief Description</u>
-024	SJRPP: Cooling Towers (2)

Fugitive particulate matter emissions from the cooling towers will be controlled with drift eliminators. No mass testing requirement will be imposed due to the physical layout.

{Permitting note(s): The emissions unit was regulated under Rule 62-212.400(5), PSD NSR Review (see PSD-FL-010 issued March 12, 1982).}

The following specific conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

G.1. Revised Tables 2 and 6, PSD-FL-010, are incorporated by reference (attached) for emissions unit 19 and 20, respectively.

G.2. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010 and PA 81-13]

G.3. Controls. The permittee shall maintain and continue to use the control systems and control techniques established to minimize particulate matter emissions from emissions unit 19 in Revised Table 2, PSD-FL-010.
[Rules 62-4.070 and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; and, PSD-FL-010 and PA 81-13]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

G.4. Particulate Matter. Particulate matter emissions from each cooling tower shall not exceed 67 lbs/hr. No mass testing requirement will be imposed due to the physical layout.
[PSD-FL-010 and PA 81-13]

Section IV. This section is the Acid Rain Part.

Operated by: Jacksonville Electric Authority
ORIS codes: 0667: Northside Generating Station
0207: St. Johns River Power Park

Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions units listed below are regulated under Acid Rain Part, Phase II.

E.U.

ID No.	Description
-001	NGS Boiler No. 1
-002	NGS Boiler No. 2 (was placed on long-term reserve shutdown on March 1, 1984)
-003	NGS Boiler No. 3
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2

A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, are a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:

a. DEP Form No. 62-210.900(1)(a), dated 07/01/95.
 [Chapter 62-213 and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO₂) allowance allocations for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003
-001 ¹	1	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	6182 ³	6182 ³	6182 ³	6182 ³
-002 ¹	2	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	6251 ³	6251 ³	6251 ³	6251 ³
-003 ¹	3	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	11061 ³	11061 ³	11061 ³	11061 ³

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003
-016 ²	1	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	11486 ³	11486 ³	11486 ³	11486 ³
-017 ²	2	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	11279 ³	11279 ³	11279 ³	11279 ³

¹ Northside Generating Station

² St. Johns River Power Park

³ The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 or 3 of 40 CFR 73.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c), F.A.C.]

A.4. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 52., APPENDIX TV-1, TITLE V CONDITIONS}

[Rule 62-214.420(11), F.A.C.]

A.5. Comments, notes, and justifications: Mr. Jon P. Eckenbach, Executive Vice President, Jacksonville Electric Authority, is the Designated Representative for Title IV purposes.

A.6. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62-214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C.

[Rules 62-213.413 and 62-214.370(4), F.A.C.]

Subsection B. This subsection addresses Acid Rain, Phase I/II.

{Permitting note: The U.S. EPA issues Acid Rain Phase I permit(s)}

The emissions unit listed below is regulated under Acid Rain Part, Phase I/II, for:

Jacksonville Electric Authority
St. Johns River Power Park
Facility ID No.: 0310045
ORIS Code: 0207

E.U. ID

<u>No.</u>	<u>Brief Description</u>
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2

B.1. The owners and operators of these Phase I/II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the permit(s) listed below:

a. Phase I permit issued 3/27/97.

[Chapter 62-213, F.A.C.]

B.2. Nitrogen oxide (NO_x) requirements for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	NO _x limit ¹
-016	1	<p>Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_x early election compliance plan for unit U1. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under "40 CFR 76.5(a)(2) of 0.50 lb/mmBtu" for dry bottom wall-fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under "40 CFR 76.7(a)(2) of 0.46 lb/mmBtu" for dry bottom wall-fired boilers until calendar year 2008.</p> <p>In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and the requirements covering excess emissions.</p>
-017	2	<p>Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_x early election compliance plan for unit U2. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under "40 CFR 76.5(a)(2) of 0.50 lb/mmBtu" for dry bottom wall-fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under "40 CFR 76.7(a)(2) of 0.46 lb/mmBtu" for dry bottom wall-fired boilers until calendar year 2008.</p> <p>In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and the requirements covering excess emissions.</p>

¹ Based on the Phase I/II NO_x Compliance Plan dated December 19, 1997.

B.3. Comments, notes, and justifications: none

Appendix U-1, List of Unregulated Emissions Units and/or Activities.

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park

PROPOSED Permit No.: 0310045-002-AV
Facility ID No.: 0310045

Unregulated Emissions Units and/or Activities. An emissions unit which emits no “emissions-limited pollutant” and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

Brief Description of Emissions Units and/or Activities:

I. Northside Generating Station.

-aaa Storage Tanks.

1. JEA Tank	Bunker C Storage	4,578,000 gallons
2. JEA Tank #12	Diesel Storage	4,200,000 gallons
3. JEA Tank #13	Diesel Storage	4,200,000 gallons
4. JEA Tank #14	Diesel Storage	4,200,000 gallons
5. JEA Tank	Waste Oil Storage - Unit 1	750 gallons
6. JEA Tank	Waste Oil Storage - Unit 2	1,000 gallons
7. JEA Tank	Waste Oil Storage - Unit 3	575 gallons
8. JEA Tank	Bunker C Storage	4,578,000 gallons
9. JEA Tank	Bunker C Storage	4,578,000 gallons
10. JEA Tank	Bunker C Storage	11,256,000 gallons
11. JEA Tank	Bunker C Storage	11,256,000 gallons
12. JEA Tank	Bunker C Storage	11,256,000 gallons
13. JEA Tank #10	Diesel Storage	168,000 gallons
14. JEA Tank #11	Diesel Storage	4,200,000 gallons

II. St. Johns River Power Park.

-bbb Storage Tanks.

1. JEA Tank: Emergency Diesel Fire Pump	Diesel Fuel Storage	1,123 gallons
2. JEA Tank: AQCS Emergency Diesel Generator Day Tank	Diesel Fuel Storage	561 gallons
3. JEA Tank	Diesel Fuel Storage	636,106 gallons
4. JEA Tank: Coal/Limestone Fuel Storage	Diesel Fuel Storage	10,069 gallons
5. JEA Tank: Ash Landfill Fuel Storage	Diesel Fuel Storage	10,069 gallons
6. JEA Tank: Power Block Emergency Generator Fuel Storage	Diesel Fuel Storage	4,015 gallons
7. JEA Tank	Gasoline Storage	10,069 gallons

Appendix I-1, List of Insignificant Emissions Units and/or Activities.

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park

PROPOSED Permit No.: 0310045-002-AV
Facility ID. No.: 0310045

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rule 62-210.300(3)(a), F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities:

I. Northside Generating Station.

A. Storage Tanks.

1. JEA Tank	Magnesium Oxide	9,600 gallons
2. JEA Tank	Petrolite	6,500 gallons
3. JEA Tank	Lube Oil - Unit 1	10,000 gallons
4. JEA Tank	Lube Oil - Unit 2	10,000 gallons
5. JEA Tank	Mineral Acid	11,500 gallons
6. JEA Tank	Mineral Acid	11,500 gallons
7. JEA Tank	Caustic - East	10,000 gallons
8. JEA Tank	Caustic - West	10,000 gallons
9. JEA Tank	Hypochlorite	12,000 gallons
10. JEA Tank	Hypochlorite	12,000 gallons
11. JEA Tank	Lube Oil	18,000 gallons
12. JEA Tank	Lube Oil	7,000 gallons

II. St. Johns River Power Park.

A. AQCS Emergency Generator.

1. The emergency generator has historically fired less than 10,000 gallons per year of diesel fuel. The emergency generator draws its fuel from a single diesel fuel oil storage tank (the fuel oil has a maximum fuel sulfur content limit of 0.76%, by weight).

B. Power Block Emergency Generator.

1. The emergency generator has historically fired less than 10,000 gallons per year of diesel fuel. The emergency generator draws its fuel from a single diesel fuel oil storage tank (the fuel oil has a maximum fuel sulfur content limit of 0.76%, by weight).

Appendix I-1, List of Insignificant Emissions Units and/or Activities (cont.).

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park

PROPOSED Permit No.: 0310045-002-AV
Facility ID No.: 0310045

C. Storage Tanks.

1. JEA Tank	Lube Oil	10,000 gallons
2. JEA Tank	Lube Oil	18,000 gallons
3. JEA Tank	Sulfuric Acid	6,000 gallons
4. JEA Tank	Sulfuric Acid	10,000 gallons
5. JEA Tank	Sulfuric Acid	6,000 gallons
6. JEA Tank	Sulfuric Acid	6,000 gallons
7. JEA Tank	Caustic	10,000 gallons
8. JEA Tank	Caustic	6,000 gallons
9. JEA Tank	Hydrazine	6,000 gallons
10. JEA Tank	Hypochlorite	6,000 gallons

III. NGS Boilers Nos. 1, 2 and 3, and SJRPP Boilers Nos. 1 and 2.

1. Evaporation of on-site generated boiler non-hazardous cleaning chemicals (cirtosolv and ammonia).
This activity occurs once every three to five years or longer.

Appendix H-1, Permit History/ID Number Changes

Jacksonville Electric Authority
 Northside Generating Station/St. Johns River Power Park (NGS/SJRPP)
 Page 1 of 2

PROPOSED Permit No.: 0310045-002-AV
Facility ID No.: 0310045

Permit History (for tracking purposes):

Northside Generating Station:

<u>E.U.</u>	<u>ID No</u>	<u>Description</u>	<u>Permit No.</u>	<u>Issue Date</u>	<u>Expiration Date</u>	<u>Extended Date</u> ^{1,2}	<u>Revised Date(s)</u>
	-001	#1 Steam Generator	AO16-194743	05/30/91	04/30/96	08/14/96, 10/26/98	11/19/91
	-002	#2 Steam Generator	AO16-178094	06/14/90	05/31/95	08/14/96, 10/26/98	
	-003	#3 Steam Generator	AO16-207528	05/20/92	02/28/97	10/26/98	05/01/95,05/04/94,08/11/92
	-004	Comb. Turbine #1 (Inactive)					
	-005	Comb. Turbine #2 (Inactive)					
	-006	Combustion Turbine #3	AO16-173886	03/09/90	01/31/95	08/14/96, 10/26/98	
	-007	Combustion Turbine #4	AO16-173886	03/09/90	01/31/95	08/14/96, 10/26/98	
	-008	Combustion Turbine #5	AO16-173886	03/09/90	01/31/95	08/14/96, 10/26/98	
	-009	Combustion Turbine #6	AO16-173886	03/09/90	01/31/95	08/14/96, 10/26/98	
	-010	Tank's #1-7	AO16-225069	05/21/93	04/30/98	10/26/98	05/26/93
	-011	Distillate Oil Tanks 10-12	AO16-225069	05/21/93	04/30/98	10/26/98	05/26/93
	-012	Oil Storage Tank 13 & 14	AO16-225069	05/21/93	04/30/98	10/26/98	
	-013	Auxiliary Boiler "B"	AO16-239735	01/06/94	11/30/98		
	-014	Auxiliary Boiler "A"	AO16-183584	10/09/90	08/31/95	10/26/98	
	all	JEA NGS/SJRPP	0310045-001-AV	10/13/98	12/31/03		

St. Johns River Power Park:

<u>E.U.</u>	<u>ID No</u>	<u>Description</u>	<u>Permit No.</u>	<u>Issue Date</u>	<u>Expiration Date</u>	<u>Extended Date</u> ^{1,2}	<u>Revised Date(s)</u>
	-016	#1 Steam Generator	PSD-FL-010 PSD-FL-010(B) PA 81-13	03/12/82 10/11/96	N/A N/A	N/A N/A	10/28/86 08/01/85
	-017	#2 Steam Generator	PSD-FL-010 PSD-FL-010(B) PA 81-13	03/12/82 10/11/96	N/A N/A	N/A N/A	10/28/86 08/01/95
	-018	#1 Auxiliary Boiler ³	PSD-FL-010 PA 81-13	03/12/82	N/A	N/A	10/28/86 08/01/95
	-018	#2 Auxiliary Boiler ³	PSD-FL-010 PA 81-13	03/12/82	N/A	N/A	10/28/86 08/01/95
	-023	Coal Storage Yard and Transfer Systems	PSD-FL-010 PA 81-13	03/12/82			10/28/86 08/01/95
	-022	Limestone and Flyash Handling	PSD-FL-010 PA 81-13	03/12/82	N/A	N/A	10/28/86 08/01/95
	-024	Cooling Towers (2)	PSD-FL-010 PA 81-13	03/12/82	N/A	N/A	10/28/86 08/01/95
	all	JEA NGS/SJRPP	0310045-001-AV	10/13/98	12/31/03		

(if applicable) ID Number Changes (for tracking purposes):

From: Facility ID No.: 31JAX160045

To: Facility ID No.: 0310045

Notes:

1 - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.

2 - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.

{Rule 62-213.420(1)(b)2., F.A.C., effective 03/20/96, allows Title V Sources to operate under existing valid permits}

3 - These emissions units are no longer in service and have been dismantled.

Table 1-1, Summary of Air Pollutant Standards and Terms

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park

PROPOSED Permit No.: 0310045-002-AV
Facility ID No.: 0310045

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of the permit.

E. U. ID No.	Brief Description	Pollutant Name	Fuel(s)	Hours/Year	Allowable Emissions			Equivalent Emissions ¹		Regulatory Citation(s)	Permit Condition
					Standard(s)	lbs/hr	TPY	lbs/hr	TPY		
-001	NGS Boiler #1 (2767 MMBtu/hr - Oil) (2892 MMBtu/hr - NG)	VE	Fuel Oil	8760	≤ 40% Opacity			N/A	N/A	62-296.405(1)(a)	A.5.
			NG	8760	≤ 40% Opacity			N/A	N/A	62-296.405(1)(a)	A.5.
	PM	Fuel Oil	8760	0.1 lb/MMBtu			276.7	1,212.0	62-296.405(1)(b)	A.8.	
		NG	8760	0.1 lb/MMBtu			289.2	1,267.0	62-296.405(1)(b)	A.8.	
	Acid Rain Phase II Unit	PM - SB ²	Fuel Oil	3 hr/day	0.3 lb/MMBtu			830.1	1,515.0	62-210.700(3)	A.9.
			NG	3 hr/day	0.3 lb/MMBtu			867.6	1,584.0	62-210.700(3)	A.9.
(297.5 MW Turbine-generator)	SO ₂	Fuel Oil	8760	1.98 lbs/MMBtu			5,478.7	23,996.5	62-296.405(1)(c)1.j.	A.10.	
		NG	8760	N/A					N/A	N/A	
	SO ₂ -%S	Fuel Oil	8760	max. S content 1.8%, by wt. ⁴			5,478.7	23,996.5	62-296.405(1)(e)3.	A.11.	
-002	NGS Boiler #2 ³ (2341 MMBtu/hr - Oil) (2352 MMBtu/hr - NG)	VE	Fuel Oil	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	A.6.
			NG	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	A.6.
	PM	Fuel Oil	8760	0.1 lb/MMBtu			234.1	1,025.4	62-296.405(1)(b)	A.8.	
		NG	8760	0.1 lb/MMBtu			235.2	1,030.2	62-296.405(1)(b)	A.8.	
	Acid Rain Phase II Unit	PM - SB	Fuel Oil	3 hr/day	0.3 lb/MMBtu			702.3	1,281.8	62-210.700(3)	A.9.
			NG	3 hr/day	0.3 lb/MMBtu			705.6	1,287.8	62-210.700(3)	A.9.
(297.5 MW Turbine-generator)	SO ₂	Fuel Oil	8760	1.98 lbs/MMBtu			4,635.2	20,302.1	62-296.405(1)(c)1.j.	A.10.	
		NG	8760	N/A					N/A	N/A	
	SO ₂ -%S	Fuel Oil	8760	max. S content 1.8%, by wt. ⁴			4,635.2	20,302.1	AO16-178094	A.11.	
-003	NGS Boiler #3 (5033 MMBtu/hr - Oil) (5260 MMBtu/hr - NG)	VE	Fuel Oil	8760	≤ 40% Opacity			N/A	N/A	62-296.405(1)(a)	A.5.
			NG	8760	≤ 40% Opacity			N/A	N/A	62-296.405(1)(a)	A.5.
	PM	Fuel Oil	8760	0.1 lb/MMBtu			503.3	2,204.5	62-296.405(1)(b)	A.8.	
		NG	8760	0.1 lb/MMBtu			526.0	2,303.9	62-296.405(1)(b)	A.8.	
	Acid Rain Phase II Unit	PM - SB	Fuel Oil	3 hr/day	0.3 lb/MMBtu			1,509.9	2,755.6	62-210.700(3)	A.9.
			NG	3 hr/day	0.3 lb/MMBtu			1,578.0	2,879.9	62-210.700(3)	A.9.
(563.7 MW Turbine-generator)	SO ₂	Fuel Oil	8760	1.98 lbs/MMBtu			9,965.3	43,648.2	62-296.405(1)(c)1.j.	A.10.	
		NG	8760	N/A					N/A	N/A	
	SO ₂ -%S	Fuel Oil	8760	max. S content 1.8%, by wt. ⁴			9,965.3	43,648.2	AO16-207528	A.11.	

E. U. ID No.	Brief Description	Pollutant Name	Fuel(s)	Hours/Year	Allowable Emissions			Equivalent Emissions ¹		Regulatory Citation(s)	Permit Condition
					Standard(s)	lbs/hr	TPY	lbs/hr	TPY		
-014	NGS Auxiliary Boiler #1 (116.5 MMBtu/hr - #6 FO) (118.0 MMBtu/hr - #2 FO) (120.0 MMBtu/hr - NG)	VE	#2/#6 FO	8760	15%; 40% - 1 two min. period/hr.	N/A	N/A	AC16-85951	B.5.		
			NG	8760	15%; 40% - 1 two min. period/hr.	N/A	N/A	AC16-85951	B.5.		
		% Sulfur	#2/#6 FO	8760	max. S content 1.8%, by wt.	233.6	1,023.3	AC16-85951	B.7.		
		SO ₂	NG	8760	N/A			N/A	N/A		
-006	NGS CT #3 ^b	VE	#2 FO	8760	<20% Opacity	N/A	N/A	62-296.3204(b)1.	C.5.		
-007	NGS CT #4 ^b	SO ₂ -%S	#2 FO	8760	max. S content 0.5%, by wt.	455.0/CT	1992.9/CT	AO16-173886	C.6.		
-008	NGS CT #5 ^b										
-009	NGS CT #6 ^b (901.0 MMBtu/hr/CT - #2 FO)										
-016	SJRPP Boiler #1	VE	All	8760	<20%; 27% - 1 six min. period/hr	N/A	N/A	40CFR60.42a(b)	D.8.		
-017	SJRPP Boiler #2 (6144 MMBtu/hr) (conditions are for each boiler) (boilers are identical)	PM	Coal, Coal & Petcoke, or Fuel Oil	8760	0.30 lb/MMBtu	1,843.2	8,073.2	40CFR60.42a(a)1.	D.6.		
		% Ash	Fuel Oil Coal/Petcoke		0.01%, by wt. 0.18%, by wt.	N/A N/A	N/A N/A	PSD-FL-010 and PA 81-13	D.7.		
Acid Rain Phase II Units (297.5 MW Turbine-generator)		SO ₂	Coal	8760	1.2 lbs/MMBtu	7,372.8	32,292.9	40CFR60.43a(a)(1),(2)&(3)	D.9.		
			Fuel Oil	8760	0.80 lb/MMBtu	4,915.2	21,528.6	40CFR60.43a(b)(1)&(2)	D.11.		
			Coal & Oil	8760	(340X + 520Y)/100			40CFR60.43a(h)(1)	D.14.		
			Oil & Coal/Petcoke	8760	(340X + 520Y)/100			40CFR60.43a(h)(2)	D.14.		
			Coal & Petcoke	8760	0.676 lb/MMBtu max.	4,153.3	18,191.6	PSD-FL-010(B)	D.10.		
		SO ₂ -%S	Coal	8760	max. S content 4.0%, by wt.	7,372.8	32,292.9	PSD-FL-010/PA 81-13	D.13.		
			Fuel Oil	8760	max. S content 0.76%, by wt.	4,915.2	21,528.6	PSD-FL-010/PA 81-13	D.13.		
			Petcoke	8760	max. S content 4.0%, by wt.	5,478.7	23,996.5	PSD-FL-010(B)	D.13.		
		NO _x	Coal	8760	0.60 lb/MMBtu	3,686.4	16,146.4	40CFR60.44a(a)(1)&(2)	D.15.		
			Fuel Oil	8760	0.30 lb/MMBtu	1,843.2	8,073.2	40CFR60.44a(a)(1)&(2)	D.15.		
	Coal & Oil	8760	(130X + 260Y)/100			40CFR60.44a(c)	D.16.				
	Oil & Coal/Petcoke	8760	(130X + 260Y)/100			40CFR60.44a(c)	D.16.				
	Coal & Petcoke	8760	0.60 lb/MMBtu	3,686.4	16,146.4	40CFR60.44a(a)(1)&(2)	D.15.				
	CO	Coal & Petcoke		No significant increase compared to coal.			PSD-FL-010(B)	D.69.			
	H ₂ SO ₄ Mist	Coal & Petcoke		No significant increase compared to coal.			PSD-FL-010(B)	D.70.			

E. U. ID No.	Brief Description	Pollutant Name	Fuel(s)	Hours/Year	Allowable Emissions			Equivalent Emissions ¹		Regulatory Citation(s)	Permit Condition				
					Standard(s)	lbs/hr	TPY	lbs/hr	TPY						
-023	SJRPP Coal Storage Yard and Transfer Systems (all ⁶)	VE			≤10% Opacity			N/A	N/A	PSD-FL-010	E.4.				
					Emissions Point ⁶				Per Unit				Per Unit		
					#4	PM			1				4.4	PSD-FL-010	E.5.
					#5				0.13				0.6		
					#6				0.57				2.5		
					#7				2.6				11.4		
					#8				1				4.4		
					#9				0.8				3.5		
					#10				0.6				2.6		
					#11				1.6				7.0		
					#12				1.8				7.9		
					#13				5				21.9		
					#14				5				21.9		
					#15				0.1				0.4		
					#16				0.5				2.2		
#17	0.02	0.1													
-022	SJRPP: Limestone and Flyash Handling				Per Unit				Per Unit		Per Unit				
	Limestone & Flyash Handling Systems	VE			≤10% Opacity		N/A	N/A	PSD-FL-010	F.4.					
	Limestone Day Silos	VE			≤10% Opacity	0.05	N/A	N/A	PSD-FL-010	F.4.					
	Flyash Day Silos & Handling Systems	PM						0.2	PSD-FL-010	F.5.					
		VE			≤10% Opacity			N/A	N/A	PSD-FL-010	F.4.				
		PM				0.2		0.9	PSD-FL-010	F.5.					
	Limestone Hopper/Transfer Conveyors	VE				≤10% Opacity		N/A	N/A	PSD-FL-010	F.4.				
		PM					0.65	2.8	PSD-FL-010	F.5.					
	Limestone Unloading (Rail Dumper)	VE				≤10% Opacity		N/A	N/A	PSD-FL-010	F.4.				
PM						0.1	0.04	PSD-FL-010	F.5.						
Limestone Transfer Points	VE				≤10% Opacity		N/A	N/A	PSD-FL-010	F.4.					
	PM					0.4	1.8	PSD-FL-010	F.5.						
-024	SJRPP: Cooling Towers (2)	PM				67/each		293.5/each	PSD-FL-010	G.4.					

Notes: NGS: Northside Generating Station; SJRPP: St. Johns River Power Park.

¹ "Equivalent Emissions" listed are for informational purposes.

⁵ Combustion turbines are identical emissions units.

² PM - SB refers to "soot blowing" and "load change".

⁶ See the emissions points listed in Revised Table 6: PSD-FL-010,

³ Placed on long-term reserve shutdown 3/1/84.

and Attachment SJRPP: Material Handling Transfer Points.

⁴ Applies when the SO₂ CEMs is temporarily inoperative.

[electronic file name: 3100451a.xls]

Table 2-1, Summary of Compliance Requirements

Jacksonville Electric Authority
 Northside Generating Station/St. Johns River Power Park

PROPOSED Permit No.: 0310045-002-AV
Facility ID No.: 0310045

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E. U. ID No.	Brief Description	Pollutant Name or Parameter	Fuel(s)	Compliance Method ⁹	Testing Time	Frequency Base Date ³	Min. Compliance Test Duration	CMS ^{1,2}	See Permit Condition(s)
					Frequency				
-001	NGS Boiler #1	VE	Fuel Oil	9	Annual ⁴	7/1 - 9/1	60 Minutes	No	A.20.
			Natural Gas	9	N/A	7/1 - 9/1	60 Minutes	No	
	Acid Rain Phase II Unit	PM	Fuel Oil	17, 5, 5B or 5F	Annual ⁴	7/1 - 9/1	1 Hour	No	A.22. & A.27.
			Natural Gas	17, 5, 5B or 5F	Annual ⁴	7/1 - 9/1	1 Hour	No	
	SO ₂	Fuel Oil	6, 6A, 6B or 6C ⁵	or FS&A ⁶	Annual ⁴	7/1 - 9/1	1 Hour	Yes ²	A.11., A.17., A.23. & A.24.
					Annual ⁴	7/1 - 9/1	1 Hour ⁷	N/A	
-002	NGS Boiler #2 (On long-term reserve shutdown since 3/1/84.)	VE	Fuel Oil	DEP Method 9	Semiannual	2/1 - 4/1	60 Minutes	No	A.20. & A.21.
			Natural Gas	DEP Method 9	N/A	2/1 - 4/1	60 Minutes	No	
	Acid Rain Phase II Unit	PM	Fuel Oil	17, 5, 5B or 5F	Semiannual	2/1 - 4/1	1 Hour	No	A.22. & A.27.
			Natural Gas	17, 5, 5B or 5F	Semiannual	2/1 - 4/1	1 Hour	No	
	SO ₂	Fuel Oil	6, 6A, 6B or 6C ⁵	or FS&A ⁶	Semiannual	2/1 - 4/1	1 Hour	No	A.11., A.17., A.23. & A.24.
					Semiannual	2/1 - 4/1	1 Hour ⁷	N/A	
-003	NGS Boiler #3	VE	Fuel Oil	9	Annual ⁴	5/1 - 7/1	60 Minutes	No	A.20.
			Natural Gas	9	N/A	5/1 - 7/1	60 Minutes	No	
	Acid Rain Phase II Unit	PM	Fuel Oil	17, 5, 5B or 5F	Annual ⁴	5/1 - 7/1	1 Hour	No	A.22. & A.27.
			Natural Gas	17, 5, 5B or 5F	Annual ⁴	5/1 - 7/1	1 Hour	No	
	SO ₂	Fuel Oil	6, 6A, 6B or 6C ⁵	or FS&A ⁶	Annual ⁴	5/1 - 7/1	1 Hour	Yes ²	A.11., A.17., A.23. & A.24.
					Annual ⁴	5/1 - 7/1	1 Hour ⁷	N/A	
	NO _x	Fuel Oil	7, 7A or 7E or RATA	Annual ⁴	5/1 - 7/1	1 Hour	Yes ¹	A.18.	
				Annual ⁴	5/1 - 7/1	1 Hour	Yes ¹		
-014	NGS Auxiliary Boiler #1	VE	No. 2 F.O.	DEP method 9	Annual ⁴	9/1 - 11/1	60 Minutes	No	B.12. & B.13.
			Natural Gas	DEP method 9	N/A	9/1 - 11/1	60 Minutes	No	
		SO ₂ -%S	No. 2 F.O.	Fuel Sampling & Analysis Provided By Vendor				No	B.7., B.14. & B.15.

E. U. ID No.	Brief Description	Pollutant Name or Parameter	Fuel(s)	Compliance Method ⁹	Testing Time Frequency	Frequency Base Date ³	Min. Compliance Test Duration	CMS ^{1,2}	See Permit Condition(s)	
-006	Combustion Turbine #3	VE	No. 2 F.O.	9	Annual ⁸	2/1 - 4/1	60 Minutes	No	C.11.	
-007	Combustion Turbine #4	SO ₂ -%S	No. 2 F.O.	Fuel Sampling & Analysis Provided By Vendor				No	C.6., C.9. & C.12.	
-008	Combustion Turbine #5									
-009	Combustion Turbine #6									
-016	SJRPP Boiler #1	VE	All	9 and CMS	Annual ⁴ & Continuous	7/1 - 9/1	60 Minutes	Yes ¹	D.28. & D.39.	
-017	SJRPP Boiler #2	PM	All	19 & 5 or 5B	Annual ⁴	7/1 - 9/1	1 Hour	No	D.39.	
	Acid Rain Phase II Units	SO ₂	All	19 and CMS	Annual ⁴ & Continuous	7/1 - 9/1	1 Hour	Yes ¹	D.29. & D.40.	
		NO _x	All	19 and CMS	Annual ⁴ & Continuous	7/1 - 9/1	1 Hour	Yes ¹	D.30. & D.41.	
		H ₂ SO ₄ Mist	Coal & Petcoke	8	Annual ⁴	7/1 - 9/1	1 Hour	No	D.70.	
-023	SJRPP Coal Storage Yard and Transfer Systems	VE	N/A	9	Annual	7/1 - 9/1	60 Minutes	No	E.9.	
		PM	N/A	5	Annual	7/1 - 9/1	1 Hour	No	E.10.	
-022	SJRPP Limestone and Flyash Handling	VE	N/A	9	Annual	7/1 - 9/1	60 Minutes	No	F.9.	
		PM	N/A	5	Annual	7/1 - 9/1	1 Hour	No	F.10.	
-024	SJRPP Cooling Towers	PM	No mass emissions test is required since there are no stacks associated with this activity.						N/A	G.4.

Notes: NGS: Northside Generating Station; SJRPP: St. Johns River Power Park.

¹ CMS [=] continuous monitoring system used for compliance.

² CMS [=] continuous monitoring system used for monitoring (24-hr: midnight to midnight).

³ Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.

⁴ Test not required while firing fuel oil in years that fuel oil is fired for less than 400 hours.

⁵ RATA can be used as a formal compliance test for SO₂ emissions.

⁶ Fuel sampling and analysis.

⁷ Hourly fuel sampling required if taken during a PM emissions compliance test.

⁸ If a combustion turbine is operated less than 400 hours per year, test is only required once every 5 years, during the year prior to permit renewal.

⁹ All test methods are EPA Methods unless stated.

[electronic file name: 3100452a.xls]

Jacksonville Electric Authority

Operation and Maintenance Plan

Operation and Maintenance

Following is a list of activities to be accomplished for the control of particulate emissions from units in or impacting the Duval County maintenance areas. These schedules apply to each on-line unit.

Daily:

1. Check and clean burners (renew tips as necessary) daily.
2. Conduct one complete soot-blowing cycle (or as needed).
3. Maintain optimum fuel oil temperature and pressure at all times.

Weekly:

1. Clean low pressure fuel oil strainers (more frequently if required).
2. Clean other fuel oil strainers as needed by monitoring the pressure drop.

Annually:

1. Clean the boiler and inspect baffles.
2. Inspect the:
 - (a) wind box;
 - (b) registers;
 - (c) diffusers;
 - (d) refractory throat;
 - (e) scanners;
 - (f) ignitors.
3. Adjust the air registers for optimum flame pattern with assistance from Engineering Services.
4. Replace burner tips (more frequently if required).

As Needed:

1. Wash furnace and air heaters.

Major Outages:

1. Overhaul the: (a) turbine/generator
(b) boiler and auxiliary equipment.
2. Calibrate the: (a) flow meters including sensing line checks;
(b) pneumatic controls;
(c) temperature gauges.

Performance Parameters

The following operational parameters are to be recorded on a bi-hourly basis.

1. Steam flow.
2. Burner oil pressure.
3. Burner oil temperature.

Fuel Type: Number 6 residual oil unless otherwise stated.

Records

Records of all operating data and maintenance procedures listed herein shall be retained at the Generating Station for review, upon request, for a period of five (5) years.

40 CFR 60 Subpart A-General Provisions
(Version dated 07/23/97)

These conditions are based on the July 1996 CFR version.

[Applicability note: These conditions are for an NSPS emissions unit (a.k.a. "federal facility") that has been built and has conducted the initial performance test(s) in accordance with 40 CFR 60.8.]

{Note: Rule 62-204.800(d), F.A.C., did not adopt/incorporate 40 CFR 60.4, 40 CFR 60.16, and 40 CFR 60.17.}

1. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.

[40 CFR 60.2; Rule 62-204.800(7)(a), F.A.C.]

40 CFR 60.7 Notification and record keeping.

2. The owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

[40 CFR 60.7(a)(4)]

3. The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 CFR 60.7(b)]

4. Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate).

Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

- (3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
- (4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
- [40 CFR 60.7(c)(1), (2), (3), and (4)]

5. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

{See attached Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance} (electronic file name: figure1.doc)

[40 CFR 60.7(d)(1) and (2)]

6. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After

demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).

[40 CFR 60.7(e)(1)]

7. Any owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least 5 (five) years following the date of such measurements, maintenance, reports, and records.

[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

40 CFR 60.8 Performance tests.

8. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

[40 CFR 60.8(c)]

40 CFR 60.11 Compliance with standards and maintenance requirements.

9. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

[40 CFR 60.11(a)]

10. Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5).

[40 CFR 60.11(b)]

11. The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

[40 CFR 60.11(c)]

12. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

[40 CFR 60.11(d)]

13. The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of EPA Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he or she shall notify the

Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which EPA Method 9 data indicates noncompliance, the EPA Method 9 data will be used to determine opacity compliance.

[40 CFR 60.11(e)(5)]

40 CFR 60.12 Circumvention.

14. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[40 CFR 60.12]

40 CFR 60.13 Monitoring requirements.

15. For the purposes of 40 CFR 60.13, all continuous monitoring systems (CMS) required under applicable subparts shall be subject to the provisions of 40 CFR 60.13 upon promulgation of performance specifications for continuous monitoring systems under Appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F of 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

[40 CFR 60.13(a)]

16. If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 60.8 and as described in 40 CFR 60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 60.8 is conducted.

[40 CFR 60.13(c)(1)]

17. (1) Owners and operators of all continuous emission monitoring systems (CEMS) installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

[40 CFR 60.13(d)(1) and (2)]

18. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems (CMS) shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

[40 CFR 60.13(e)(1) and (2)]

19. All continuous monitoring systems (CMS) or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of 40 CFR 60 shall be used.

[40 CFR 60.13(f)]

20. When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems (CMS) on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

[40 CFR 60.13(g)]

21. Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally

spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O₂ or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

[40 CFR 60.13(h)]

[electronic file name: 40CFR60a.doc]

Attachment NGS: CT Heat Input Nominal Values

NORTHSIDE STATION COMBUSTION TURBINES
BASE LOAD MW vs TEMPERATURE

AMBIENT TEMP #	TEMP °F	GROSS MW (X)	x Coeff. Net MW	HEAT CONSUMED MBTU/HR	AMBIENT TEMP #	TEMP °F	GROSS MW (X)	x Coeff. Net MW	HEAT CONSUMED MBTU/HR
1	20	67.97	67.63	868	60	58.77	58.43	747	
2	21	67.74	67.40	865	61	58.54	58.20	744	
3	22	67.51	67.17	861	62	58.31	57.97	741	
4	23	67.28	66.94	858	63	58.08	57.74	738	
5	24	67.05	66.71	855	64	57.85	57.51	735	
6	25	66.82	66.48	852	65	57.62	57.28	733	
7	26	66.59	66.25	849	66	57.39	57.05	730	
8	27	66.36	66.02	846	67	57.16	56.82	727	
9	28	66.13	65.79	842	68	56.93	56.59	724	
10	29	65.90	65.56	839	69	56.70	56.36	721	
11	30	65.67	65.33	836	70	56.47	56.13	719	
12	31	65.44	65.10	833	71	56.24	55.90	716	
13	32	65.21	64.87	830	72	56.01	55.67	713	
14	33	64.98	64.64	827	73	55.78	55.44	710	
15	34	64.75	64.41	824	74	55.55	55.21	708	
16	35	64.52	64.18	821	75	55.32	54.98	705	
17	36	64.29	63.95	818	76	55.09	54.75	702	
18	37	64.06	63.72	815	77	54.86	54.52	699	
19	38	63.83	63.49	812	78	54.63	54.29	697	
20	39	63.60	63.26	809	79	54.40	54.06	694	
21	40	63.37	63.03	806	80	54.17	53.83	691	
22	41	63.14	62.80	802	81	53.94	53.60	689	
23	42	62.91	62.57	799	82	53.71	53.37	686	
24	43	62.68	62.34	796	83	53.48	53.14	683	
25	44	62.45	62.11	793	84	53.25	52.91	681	
26	45	62.22	61.88	791	85	53.02	52.68	678	
27	46	61.99	61.65	788	86	52.79	52.45	675	
28	47	61.76	61.42	785	87	52.56	52.22	673	
29	48	61.53	61.19	782	88	52.33	51.99	670	
30	49	61.30	60.95	779	89	52.10	51.76	667	
31	50	61.07	60.73	776	90	51.87	51.53	665	
32	51	60.84	60.50	773	91	51.64	51.30	662	
33	52	60.61	60.27	770	92	51.41	51.07	660	
34	53	60.38	60.04	767	93	51.18	50.84	657	
35	54	60.15	59.81	764	94	50.95	50.61	654	
36	55	59.92	59.58	761	95	50.72	50.38	652	
37	56	59.69	59.35	758	96	50.49	50.15	649	
38	57	59.46	59.12	755	97	50.26	49.92	647	
39	58	59.23	58.89	753	98	50.03	49.69	644	
40	59	59.00	58.66	750	99	49.80	49.46	641	
41	60	58.77	58.43	747	100	49.57	49.23	639	

KSCT
Y INTERCEPT 72.576
SLOPE 0.2301

DISPATCH HEAT RATE CURVES

A = 1.78910E+02
B = 8.82453E+00
C = -1.50705E-02
D = 5.20028E-04
AA = 3.40192E-01
BB = 9.99987E-01
CC = 1.79499E-07
DATE: 05/21/93

Table 6. Allowable Emission Limits (Revised: From PSD Permit)

Emission Unit	SO ₂	NO _x (lb/hour: lb/MMBtu)	PM (Revised Original)	Opacity (Percent)
1. Steam Generating Boiler No.1 (6,144 MMBtu/hr maximum heat input)	4,669.: 0.76 (30-day rolling average)	3,686: 0.6	184 0.03	20
2. Steam Generating Boller No. 2 (6,144 MMBtu/hr maximum heat input)	4,669: 0.76 (30-day rolling average)	3,686: 0.6	184: 0.03	20
3. Auxiliary coolers (254 MMBtu/hr maximum heat input total)	203: 0.8		25.0: 0.1	20
4. Ship Unloading (2 Grab Buckets)			1.0	10
5. Feeders to Conveyor A (2 Wet Suppre-sion points)*			0.13	10
6. Conveyor Transfers 1 & 2 (2 points)*			0.57	10
7. Conveyor Transfer 3, 4, 5 & D to D by-pass (4 points)*			2.6	10
8. Conveyor Transfers 6 & 7 (2 points)*			1.0	10
9. Traveling Stacker (3 points)*			0.8	10
10. Bucket Wheel Reclaimer (2 points)*			0.6	10
11. Ship unloading facility coal storage pile			1.6	10
12. Coal handling transfer points ship unloading facility coal pile (8 points)*			1.8	10
13. Rail car unloading (Rotary Dumper)			5	10
14. Coal handling transfer points (6 wet suppression points)			5 (each)	10
15. Coal handling transfer points (11 dry colleccion)			0.1 (each)	10
16. Coal storage at plant. (10 acres active)			0.5	10
17. Coal storage at plant* (2 to 13-acre inactive piles)			0.02	10
18. Limestone unloading (rail dumper)			0.1	10
19. Limestone transfer points			0.4 (each)	10
20. Cooling towers			67 (Each tower)	N/A

* Revised emission unit, May 1986.