Date: 11/13/97 4:45:07 PM
From: Elizabeth Walker TAL
Subject: New Posting
To: See Below

There is a new posting on the Florida Website

JACKSONVILLE ELECTRIC AUTHORITY
NORTHSIDE/SJRPP
0310045001AV

Proposed

The notification letter is encoded and attached. If you have any questions, please let me know.

Thanks

Elizabeth

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

November 13, 1997

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

Re: PROPOSED Title V Permit No.: 0310045-001-AV
Jacksonville Electric Authority Northside Generating Station/St. Johns River Power Park

Dear Mr. Brussels:

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://www.dep.state.fl.us/air*.

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permit will not be issued until the permitting authority receives written notice that the objection is resolved or withdrawn.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 850/488-1344.

Sincerely,

CH Fancy

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

CHF/BM/m

Enclosures

Copy furnished to:
Mr. Walter P. Brussels, Managing Director/Responsible Official, JEA
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. Yolanda Adams, U.S. EPA, Region 4 (INTERNET E-mail Memorandum)

11/17/97 cc: Bruce Mitchell
Reading File

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. Jon P. Eckenbach
Executive Vice President
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

4a. Article Number
P 265 657 313

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

7. Date of Delivery
11/18/97

5. Signature (Addressee)

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

6. Signature (Agent)
[illegible]

PS Form 3811, December 1991 ★U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

Is your RETURN ADDRESS completed on the reverse

- Complete items 3, and 4a & b.
- Print your name and address on the reverse o
return this card to you.
- Attach this form to the front of the mailpiece, or on th
does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article num
- 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. Brussels
Managing Director
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

4a. Article Number
P 265 657 312

4b. Service Type
☐ Registered ☐ Insured
XX Certified ☐ COD
☐ Express Mai ☐ Return Receipt for Merchandise

7. Date of Delivery
11/18/97

5. Signature (Addressee)

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

6. Signature (Agent)
[illegible]

PS Form 3811, December 1991 ★U.S. GPO: 1992—323-402 **DOMESTI C RETURN RECEIPT**

Thank you for using Return Receipt Service.

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. Richard Breitmoser, P.E.
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

4a. Article Number
P 265 657 314

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

7. Date of Delivery
6/18/97

5. Signature (Addressee)

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

6. Signature (Agent)
[illegible]

PS Form 3811, December 1991 ★U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 265 657 312

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Mr. Walter P. Brussels	
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 11/17/97 JEA - Northside/St. John's ID#0310045-001-AV	

PS Form 3800, April 1995

P 265 657 313

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Mr. Jon P. Eckenbach	
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 11/17/97 JEA - Northside/St. John's ID#0310045-001-AV	

P 265 657 314

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Mr. Richard Breitmoser, P.E.	
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 11/17/97 JEA - Northside/St. John's ID#0310045-001-AV	

PS Form 3800, April 1995

P 265 657 315

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. Bert Gianazza
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

4a. Article Number
P 265 657 315

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

7. Date of Delivery
11/18/97

5. Signature (Addressee)

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

6. Signature (Agent)
D. Cole

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to	Mr. Bert Gianazza
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	11/17/97 - JEA - Northside/St. John's ID#0310045-001-AV

PS Form

P 265 657 316

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. James L. Manning, PE Chief
Air & Water Quality Division
Regulatory & Environmental Services Department (RESD)
Suite 422, 421 West Church Street
Jacksonville, Florida 32202-4111

4a. Article Number
P 265 657 316

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

7. Date of Delivery
11/18/97

5. Signature (Addressee)

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

6. Signature (Agent)
Nadine Schemes

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to	Mr. James L. Manning
Street & Number	421 West Church St.,Suite 422
Post Office, State, & ZIP Code	Jacksonville, FL 32202-4111
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	11/17/97 - JEA - Northside/St. Johns ID#0310045-001-AV

PS Form 38

PROPOSED PERMIT DETERMINATION

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

PROPOSED Permit No.: **0310045-001-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 3, 1997. The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was published in the The Florida Times-Union on October 4, 1997. 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 October 22, 1997.

II. Public Comment(s).

No comments were received during the 30 (thirty) day public comment period. Since no comments were received, the DRAFT Title V Air Operation Permit becomes the PROPOSED Title V Air Operation Permit.

STATEMENT OF BASIS

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

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0310045-001-AV

This Title V air operation permit 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 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 boilers, NGS No. 1 and SJRPP Nos. 1 and 2. The NGS and SJRPP auxiliary boilers are 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 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, 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 168 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 195 feet. NGS Boiler No. 2 began commercial operation in 1972. **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 235.3 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).

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 pet 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 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 March 1986. SJRPP Boiler No. 2 began commercial operation in May 1988.

The SJRPP boilers are regulated under Acid Rain, Phase II; 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 auxiliary boilers Nos. 1 and 2 are steam generators that are allowed to fire new No. 2 distillate fuel oil. The maximum fuel oil sulfur content is 0.76%, by weight (BACT dated 05/07/81). Emissions from the boilers are uncontrolled. The SJRPP Auxiliary Boilers Nos. 1 and 2 were authorized construction on 03/12/82. These emissions units are to be utilized to provide startup and shutdown capability for SJRPP Boilers Nos. 1 and 2 and when one or both of the main boilers is/are out of service.

The SJRPP auxiliary boilers Nos. 1 and 2 are 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 05/07/81).

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.

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).

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

Florida's DRAFT Permit Electronic Notification Cover Memorandum

TO: Yolanda Adams, U.S. EPA Region 4

CC: Carla E. Pierce, U.S. EPA Region 4

THRU: Scott M. Sheplak, P.E., Tallahassee Title V Section

FROM: Bruce Mitchell, Permit Engineer

DATE: 11/13/97

RE: U.S. EPA Region 4 PROPOSED Title V Operation Permit Review

The following DRAFT Title V operation permit(s) and associated documents have been posted on the DEP World Wide Web Internet site for your review. Please provide any comments via. Internet E-mail, to Scott M. Sheplak, P.E., at "Sheplak_S@dep.state.fl.us".

Applicant Name	County	Method of Transmittal	Electronic File Name(s)
JEA-Northside Generating Station/ St. Johns River Power Park	Duval	INTERNET	0310045p.zip

This zipped file contains the following electronic files:

0310045.sob
0310045.pd
0310045p.doc
03100451.xls
03100452.xls
0310045e.doc
0310045u.doc
0310045h.doc

v:\0310045p.zip

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

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0310045-001-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

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0310045-001-AV

Table of Contents

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

Permittee:
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

PROPOSED Permit No.: 0310045-001-AV
Facility ID No.: 0310045
SIC No.: 49; 4911
Project: Initial Title V Air Operation Permit

This permit is for the operation of 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 is issued under the provisions of Chapter 403, Florida Statutes (F.S.); Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214; 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 E-1, List of Exempt Emissions Units and/or Activities
APPENDIX TV-1, TITLE V CONDITIONS (version dated 08/11/97)
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)
BACT Determinations dated 10/15/84 (NGS) and 05/07/81 (SJRPP)
PSD-FL-010(B) issued 10/14/96
Operation and Maintenance Plan
Phase II Acid Rain Application/Compliance Plan received 12/26/95
Alternate Sampling Procedure: ASP Number 97-B-01
Appendix 40CFR60 Subpart A - General Provisions (dated 07/23/97)

Effective Date: January 1, 1998
Renewal Application Due Date: July 5, 2002
Expiration Date: December 31, 2002

Howard L. Rhodes, Director
Division of Air Resources Management

HLR/sms/bm

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 boilers, NGS No. 1 and SJRPP Nos. 1 and 2. The NGS and SJRPP auxiliary boilers are 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 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, 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.

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. ID No.	Brief Description
-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
-rrr	SJRPP Boiler No. 1
-sss	SJRPP Boiler No. 2
-ttt	SJRPP Auxiliary Boilers Nos. 1
-uuu	SJRPP Auxiliary Boilers Nos. 2
-vvv	SJRPP: Coal Storage Yard and Transfer Systems
-www	SJRPP: Limestone and Flyash Handling
-xxx	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.

<u>These documents are provided to the permittee for information purposes only:</u>
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

<u>These documents are on file with the permitting authority:</u>
Initial Title V Permit Application received June 14, 1996.
Supplementary information received September 16, 1996.
PSD-FL-010(B) issued October 14, 1996.
Supplementary information received January 9, 1997.
Supplementary information received September 17, 1997.

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 not 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. Exempt Emissions Units and/or Activities. Appendix E-1, List of Exempt 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.
[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
Operating Permits 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.

<u>E.U. ID</u> <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 168 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 195 feet. NGS Boiler No. 2 began commercial operation in 1972. **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 235.3 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:

Emissions Unit	MMBtu/hr Heat Input	Fuel Type
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.
[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.
[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. SO_2 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 SO_2 continuous emissions monitor system is temporarily inoperative. For Boiler No. 2, the maximum sulfur content shall not exceed 1.8%, by weight. See specific condition **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 NO_2). For Boiler No. 3, nitrogen oxides shall not exceed 0.30 lb/MMBtu heat input, as measured by applicable compliance methods.
[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**.

CONSTITUENT / PROPERTY*	ALLOWABLE LEVEL
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 SO_2 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 NO_2) 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 62-296.450(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 EPA 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 SO_2 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 a SO_2 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 $\bar{S}O_2$ 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 SO_2 emissions between 90 to 100% of the SO_2 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:
  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;
  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.

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.
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:

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:

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]

<u>Record keeping and Reporting Requirements</u>

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. <u>Test Reports</u>.
(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.

E.U. ID No.	**Brief Description**
-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:

Unit No.	MMBtu/hr Heat Input	Fuel Type
Aux. Boiler No. 1	120.0	Natural Gas
	120.0	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

[AC16-85951; and, application received June 14, 1997.]

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**.

CONSTITUENT / PROPERTY*	ALLOWABLE LEVEL
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;
   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:

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.

E.U. ID No.	Brief Description
-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 (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

{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:

Unit No.	MMBtu/hr Heat Input	Fuel Type
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

[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 (virgin) 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.
[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;

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.

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; AO16-173880; and, SIP approved]

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.
[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. ID No.	Brief Description
-rrr	SJRPP Boiler No. 1
-sss	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 pet 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 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 March 1986. SJRPP Boiler No. 2 began commercial operation in May 1988.

{Permitting note(s): The emissions units are regulated under Acid Rain, Phase II; 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:

Essential Potential to Emit (PTE) Parameters

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

Emissions Unit No.	MMBtu/hr Heat Input
-rrr	6,144
-sss	6,144

[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.48.** [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 (averaged over 24 hours).

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 SO_2 removal efficiency less than 90 percent <u>or</u> 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 SO_2 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. <u>Hours of Operation</u>. 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]

<u>Emission Limitations and Standards</u>

{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. <u>Particulate Matter</u>. 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. <u>Ash Content</u>.
a. The maximum ash content of the coal is 0.18%, 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) SO_2 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 SO_2 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 SO_2 emissions shall not exceed the following formula:

$$SO_2\ (\text{lb/MMBtu}) = (0.2 \times C/100) + 4$$

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 SO_2 emissions shall not exceed the following formula:

$$SO_2\ (\text{lb/MMBtu}) = [0.1653 \times C \times S - 0.4 \times (C + 40)] \times 1/100$$

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

d. The maximum SO_2 emissions rate when co-firing petroleum coke and coal shall not exceed 0.676 lb/MMBtu heat input.

e. Compliance with the SO_2 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, 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.
a. The coal sulfur content shall not exceed 4.0 percent, by weight, dry basis.
b. The petroleum coke sulfur content shall not exceed 4.0 percent, by weight, dry basis.
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 SO_2 to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input:

$PS_{SO2} = (340X + 520Y)/100$ and
$\%P_S = 10$

(2) If emissions of SO_2 to the atmosphere are less than 260 ng/J (0.60 lb/MMBtu) heat input:

$PS_{SO2} = (340X + 520Y)/100$ 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 SO_2 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. Bituminous coal: 0.60 lb/million Btu (260 ng/J) heat input;
b. All other fuels - 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.46., D.65., D.66.** and **D.67**.

CONSTITUENT / PROPERTY-*	ALLOWABLE LEVEL
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]

D.18. Carbon Monoxide. Carbon monoxide emissions shall not exceed 0.05 lb/MMBtu heat input.
[PSD-FI-010 BACT]

Excess Emissions

D.19. Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:
(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.
(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:
(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under 40 CFR 60.43.
(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44.
[40 CFR 60.45(g)(1), (2) & (3)]

D.20. 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]

D.21. 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.22. 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.23. 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.24. 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.25. 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.26. 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.27. 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.28. Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 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 (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emissions rates for the 30 successive boiler operating days.
[40 CFR 60.46a(g)]

D.29. 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.30. 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 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.31. 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.32. 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.33. 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.34. 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.35. 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.36. 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.37. 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 SO_2 concentration at the same location as the SO_2 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 O_2 or CO_2 concentration at the same location as the O_2 or CO_2 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.38. 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 O_2, SO_2, and NO_X concentrations.
(2) SO_2 or NO_X (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, 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.39. 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.75.**); 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)]

<u>Test Methods and Procedures</u>

{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.40. 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 for SO_2 and NO_X. Acceptable alternative methods are given in 40 CFR 60.48a(e).
[40 CFR 60.48a(a)]

D.41. <u>Particulate Matter</u>. 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.42. 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.43. 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 CO_2 or O_2.
[40 CFR 60.48a(d)(1) & (2)]

D.44. 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 (CO_2) 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 CO_2 shall be determined in the same manner as the O_2 concentration.
[40 CFR 60.48a(e)(1) & (2)]

D.45. Carbon Monoxide. Compliance shall be demonstrated using EPA Method 10 in accordance with Chapter 62-297, F.A.C.
[Rules 62-213.440 and 62-297.401, F.A.C.; Part V, Rule 2.501, JEPB; and, Part XI, Rule 2.1001, JEPB]

D.46. 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.65., D.66.** and **D.67**.
[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.47. 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.48. 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.49. 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.50. 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.51. 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.52. <u>Frequency of Compliance Tests</u>. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) <u>General Compliance Testing</u>.

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;

   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.

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.

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) <u>Special Compliance Tests</u>. 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) <u>Waiver of Compliance Test Requirements</u>. 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.53. Stack tests for particulate matter, nitrogen oxides, sulfur dioxide, and visible emissions shall be performed annually.
[PA 81-13]

Record keeping and Reporting Requirements

D.54. 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.55. 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 (SO_2 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.56. 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.57. 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.58. 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.59. 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.60. 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.61. 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.62. The owner or operator of an affected facility shall submit the written reports required under 40 CFR 60.49(a) 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.63. 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.64. <u>Test Reports</u>.
(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.65. 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.46., D.66.** and **D.67.**
[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.66. 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.46., D.65.** and **D.67.**
[Rule 62-213.440(1)(b)2.b., F.A.C.; and, Part V, Rule 2.501, JEPB]

D.67. 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, the heating value, and sulfur and ash content, percent by weight, of each fuel fired.
[Rule 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010 and PA 81-13]

D.68. 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 submitted to the AWQD with each AOR.
[Rule 62-213.440, F.A.C.; and, Part V, Rule 2.501, JEPB]

D.69. 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.70. 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.71. 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.72. 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.73. 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.74. 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.75. 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, SO_2 and NO_X may be determined by using the Fc factor, provided that the following procedure is used:

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

$$E = C\ F_c\ (100 / \%\ CO_2)$$

where:
E = emission rate of pollutant, ng/J (lb/million Btu).
C = concentration of pollutant, ng/dscm (lb/dscf).
$\%\ CO_2$ = 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 ($\overline{d}$) 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 $\overline{d}$ 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)]

Section III. Emissions Units.

Subsection E. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
-ttt	SJRPP Auxiliary Boiler No. 1
-uuu	SJRPP Auxiliary Boiler No. 2

The SJRPP Auxiliary Boilers Nos. 1 and 2 are steam generators that are allowed to fire new No. 2 distillate fuel oil. The maximum fuel oil sulfur content is 0.76%, by weight (BACT dated 05/07/81). Emissions from the boilers are uncontrolled. The SJRPP Auxiliary Boilers Nos. 1 and 2 were authorized construction on 03/12/82. These emissions units are to be utilized to provide startup and shutdown capability for SJRPP Boilers Nos. 1 and 2 and when one or both of the main boilers is/are out of service.

{Permitting note(s): The emissions units are 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 05/07/81).}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
Aux. Boiler No. 1	127.0	New No. 2 Fuel Oil
Aux. Boiler No. 2	127.0	New No. 2 Fuel Oil

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

E.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **E.20.**
[Rule 62-297.310(2), F.A.C.; Part XI, Rule 2.1101, JEPB]

E.3. Methods of Operation.
a. The only fuel allowed to be fired is new No. 2 distillate fuel oil.
b. These emissions units are to be utilized to provide startup and shutdown capability for SJRPP Boilers Nos. 1 and 2 and when one or both of the main boilers is/are out of service.
[Rule 62-213.410, F.A.C.; Part V, Rule 2.301, JEPB; and, PSD-FL-010, PA 81-13 and BACT]

E.4. Hours of Operation. These emissions units may operate continuously, i.e., 8760 hours/year, but only when at least one of the main steam generating boilers (SJRPP Boiler No. 1 or No. 2) is either out of service or in the startup or shutdown mode of operation.
[PSD-FL-010 and PA 81-13]

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.}

E.5. Revised Table 6, PSD-FL-010, is incorporated by reference (attached) for emissions unit 3.

E.6. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent.
[Rules 62-296.406(1), F.A.C.; and, Part X, Rule 2.1001, JEPB]

E.7. Particulate Matter. Particulate matter emissions shall not exceed neither 0.1 lb/MMBtu heat input nor 12.7 lbs/hr from each boiler. Particulate matter emissions shall be controlled by the firing low sulfur content liquid fuel oil. See specific condition **E.8**.
[Rule 62-296.406(2), F.A.C.; Part X, Rule 2.1001, JEPB; and, PSD-FL-010 and BACT]

E.8. Sulfur Dioxide. Sulfur dioxide emissions shall not exceed neither 0.8 lb/MMBtu heat input nor 101.6 lbs/hr from each boiler. Sulfur dioxide emissions shall be controlled by the firing low sulfur content liquid fuel oil. See specific condition **E.9**.
[PSD-FL-010]

E.9. Sulfur Dioxide - Sulfur Content. The maximum sulfur content of the new No. 2 distillate fuel oil is 0.76 percent, by weight. See specific conditions **E.17.** and **E.18**.
[Rule 62-296.406(3), F.A.C.; Part X, Rule 2.1001, JEPB; and, PSD-FL-010 and BACT]

E.10. Ash Content. The ash content in the new No. 2 distillate fuel oil shall not exceed 0.01%, by weight.
[PSD-FL-010, PA 81-13 and BACT]

Excess Emissions

E.11. 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]

E.12. 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

E.13. 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.14. 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.}

E.15. Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. See specific condition **E.16.**
[Rules 62-213.440 and 62-297.401, F.A.C.; Part XI, Rule 2.1101, JEPB]

E.16. 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]

E.17. Particulate Matter. EPA Methos 5 shall be the method for compliance pursuant to Chapter 62-297, F.A.C.
[Rules 62-213.440 and 62-297.401, F.A.C.; and, Part XI, Rule 2.1101, JEPB]

E.18. 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 **E.9.** and **E.18.**
[Rules 62-213.440 and 62-296.406(3), F.A.C.]

E.19. 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 **E.9.** and **E.17.**
[Rules 62-213.440, 62-296.406(3) and 62-297.440, F.A.C.]

E.20. Ash Content. The fuel ash content, percent by weight, for liquid fuels shall be evaluated using either ASTM D396-78, ASTM D975-78, or the latest edition. See specific condition **E.10.**
[PSD-FL-010 and PA 81-13]

E.21. 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]

E.22. 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]

E.23. <u>Frequency of Compliance Tests</u>. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) <u>General Compliance Testing</u>.

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;

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 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) <u>Special Compliance Tests</u>. 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) <u>Waiver of Compliance Test Requirements</u>. 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]

E.24. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning 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]

Record keeping and Reporting Requirements

E.25. 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.26. 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]

E.27. 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 conditions **E.16.** and **E.17.**
[PSD-FL-010 and PA 81-13]

E.28. When any of the SJRPP boilers, Nos. 1 and 2, are shut down, it shall be recorded in the boiler's operating log book.
[Rule 62-213.440, F.A.C.; and, Part V, Rule 2.501, JEPB]

Section III. Emissions Unit(s) and Conditions.

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

E.U. ID No.	**Brief Description**
-vvv	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. 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:

<u>**Essential Potential to Emit (PTE) Parameters**</u>

F.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.

F.2. <u>Permitted Capacity</u>. The maximum throughput rate shall not exceed the amount established in Revised Table 2, PSD-FL-010.
[Rules 62-4.070 and 62-210.200(PTE), F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010]

F.3. <u>Emissions Unit Operating Rate Limitation After Testing</u>. See specific condition **F.13.**
[Rule 62-297.310(2), F.A.C.; Part XI, Rule 2.1101, JEPB]

F.4. <u>Hours of Operation</u>. 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]

F.5. <u>Controls</u>. 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.}

F.6. 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]

F.7. 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

F.8. 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.9. 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.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.; 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.11. 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 **F.12.**
[40 CFR 60.252(c); and, PSD-FL-010 and PA 81-13]

F.12. 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 **F.11.**
[Rules 62-4.070 and 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010]

F.13. 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]

F.14. 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]

F.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;

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

F.16. 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.17. 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.

F.18. 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 G. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
-www	SJRPP: Limestone and Flyash Handling

Fugitive particulate matter emissions will be generated from limestone and flyash handling and storage systems. 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.

{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

G.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.

G.2. Permitted Capacity. The maximum throughput rate shall not exceed the amount established in Revised Table 2, PSD-FL-010.
[Rules 62-4.070 and 62-210.200(PTE), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010]

G.3. Emissions Unit Operating Rate Limitation After Testing. See specific condition **G.11**.
[Rule 62-297.310(2), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

G.4. 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]

G.5. 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.}

G.6. 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 day silos	10% opacity
d. Limestone unloading (rail dumper)	10% opacity
e. Flyash silos	10% opacity

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

G.7. Particulate Matter. Particulate matter emissions shall not exceed the following:

a. Limestone silo	0.050 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

G.8. 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]

G.9. 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

G.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: 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.}

G.11. 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]

G.12. 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]

G.13. 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 2.1101, JEPB]

G.14. 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]

G.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;

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

G.16. 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]

G.17. 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 H. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
-xxx	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 is 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

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

H.2. Permitted Capacity. The maximum throughput rate shall not exceed the amount established in Revised Table 2, PSD-FL-010.
[Rules 62-4.070 and 62-210.200(PTE), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010]

H.3. 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]

H.4. 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.}

H.5. 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 (297.5 MW electric steam generator)
-002	NGS Boiler No. 2 (297.5 MW electric steam generator; was placed on long-term reserve shutdown on March 1, 1984)
-003	NGS Boiler No. 3 (563.7 MW electric steam generator)
-rrr	SJRPP Boiler No. 1 (679.6 MW electric steam generator)
-sss	SJRPP Boiler No. 2 (679.6 MW electric steam generator)

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, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO_2) allowance allocations and nitrogen oxide (NO_x) requirements for each Acid Rain unit is as follows:

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

E.U. ID No.	EPA ID	Year	2000	2001	2002
-rrr**	1	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	11486***	11486***	11486***
		NOx limit	****	****	****
-sss**	2	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	11279***	11279***	11279***
		NOx limit	****	****	****

* Northside Generating Station
** St. Johns River Power Park
*** 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.
**** If applicable, by January 1, 1999, this Part will be reopened to add NOx requirements in accordance with the regulations implementing section 407 of the Clean Air Act.

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.
1. 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.
2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
3. 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 51., 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 Company, has become the new Designated Representative for Title IV purposes.

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

Jacksonville Electric Authority **PROPOSED Permit No.:** 0310045-001-AV
Northside Generating Station/St. Johns River Power Park

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 E-1, List of Exempt Emissions Units and/or Activities.

Jacksonville Electric Authority **PROPOSED Permit No.:** 0310045-001-AV
Northside Generating Station/St. Johns River Power Park

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Full 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 whether a facility containing such emissions units or activities would be subject to any applicable requirements. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., are also exempt from the permitting requirements of Chapter 62-213, F.A.C., provided such emissions units and activities also meet the exemption criteria of Rule 62-213.430(6)(b), F.A.C. The below listed emissions units and/or activities are hereby exempt 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).

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

PROPOSED Permit No.: 0310045-001-AV
Facility ID No.: 0310045

Permit History (for tracking purposes):

Northside Generating Station:

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

Appendix H-1 (cont.): 0310045-001-AV

St. Johns River Power Park:

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1,2]	Revised Date(s)
-rrr	#1 Steam Generator	PSD-FL-010	03/12/82	N/A	N/A	10/28/86
		PSD-FL-010(B)	10/11/96	N/A	N/A	
		PA 81-13				08/01/85
-sss	#2 Steam Generator	PSD-FL-010	03/12/82	N/A	N/A	10/28/86
		PSD-FL-010(B)	10/11/96	N/A	N/A	
		PA 81-13				08/01/95
-ttt	#1 Auxiliary Boiler	PSD-FL-010	03/12/82	N/A	N/A	10/28/86
		PA 81-13				08/01/95
-uuu	#2 Auxiliary Boiler	PSD-FL-010	03/12/82	N/A	N/A	
		PA 81-13				08/01/95
-vvv	Coal Storage Yard and Transfer Systems	PSD-FL-010	03/12/82			10/28/86
		PA 81-13				08/01/95
-www	Limestone and Flyash Handling	PSD-FL-010	03/12/82	N/A	N/A	10/28/86
		PA 81-13				08/01/95
-xxx	Cooling Towers (2)	PSD-FL-010	03/12/82	N/A	N/A	10/28/86
		PA 81-13				08/01/95

(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}

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

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

PROPOSED Permit No.: 0310045-001-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 Standard(s)	Allowable Emissions lbs/hr	Allowable Emissions TPY	Equivalent Emissions[1] lbs/hr	Equivalent Emissions[1] TPY	Regulatory Citation(s)	Permit Condition
-001	NGS Boiler #1	VE	Fuel Oil	8760	≤40% Opacity			N/A	N/A	62-296.405(1)(a)	A.5.
	(2767 MMBtu/hr - Oil)		NG	8760	≤40% Opacity			N/A	N/A	62-296.405(1)(a)	A.5.
	(2892 MMBtu/hr - NG)	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.
		PM - SB[2]	Fuel Oil	3 hr/day	0.3 lb/MMBtu			830.1	1,515.0	62-210.700(3)	A.9.
	Acid Rain Phase II Unit		NG	3 hr/day	0.3 lb/MMBtu			867.6	1,584.0	62-210.700(3)	A.9.
		SO_2	Fuel Oil	8760	1.98 lbs/MMBtu			5,478.7	23,996.5	62-296.405(1)(c)1.j.	A.10.
	(297.5 MW Turbine-generator)		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]	VE	Fuel Oil	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	A.6.
	(2341 MMBtu/hr - Oil)		NG	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	A.6.
	(2352 MMBtu/hr - NG)	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.
		PM - SB	Fuel Oil	3 hr/day	0.3 lb/MMBtu			702.3	1,281.8	62-210.700(3)	A.9.
	Acid Rain Phase II Unit		NG	3 hr/day	0.3 lb/MMBtu			705.6	1,287.8	62-210.700(3)	A.9.
		SO_2	Fuel Oil	8760	1.98 lbs/MMBtu			4,635.2	20,302.1	62-296.405(1)(c)1.j.	A.10.
	(297.5 MW Turbine-generator)		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	VE	Fuel Oil	8760	≤40% Opacity			N/A	N/A	62-296.405(1)(a)	A.5.
	(5033 MMBtu/hr - Oil)		NG	8760	≤40% Opacity			N/A	N/A	62-296.405(1)(a)	A.5.
	(5260 MMBtu/hr - NG)	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.
		PM - SB	Fuel Oil	3 hr/day	0.3 lb/MMBtu			1,509.9	2,755.6	62-210.700(3)	A.9.
	Acid Rain Phase II Unit		NG	3 hr/day	0.3 lb/MMBtu			1,578.0	2,879.9	62-210.700(3)	A.9.
		SO_2	Fuel Oil	8760	1.98 lbs/MMBtu			9,965.3	43,648.2	62-296.405(1)(c)1.j.	A.10.
	(563.7 MW Turbine-generator)		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 Standard(s)	Allowable Emissions lbs/hr	Allowable Emissions TPY	Equivalent Emissions[1] lbs/hr	Equivalent Emissions[1] TPY	Regulatory Citation(s)	Permit Condition
-014	NGS Auxiliary Boiler #1	VE	#2/#6 FO	8760	15%; 40% - 1 two min. period/hr.			N/A	N/A	AC16-85951	B.5.
	(116.5 MMBtu/hr - #6 FO)		NG	8760	15%; 40% - 1 two min. period/hr.			N/A	N/A	AC16-85951	B.5.
	(118.0 MMBtu/hr - #2 FO)	% Sulfur	#2/#6 FO	8760	max. S content 1.8%, by wt.			233.6	1,023.3	AC16-85951	B.7.
	(120.0 MMBtu/hr - NG)	SO_2	NG	8760	N/A					N/A	N/A
-006	NGS CT #3	VE	#2 FO	8760	<20% Opacity			N/A	N/A	62-296.320(4)(b)1.	C.5.
-007	NGS CT #4	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										
-009	NGS CT #6										
	(901.0 MMBtu/hr/CT - #2 FO)										
-rrr	SJRPP Boiler #1	VE	All	8760	$\leq$20%; 27% - 1 six min. period/hr			N/A	N/A	40CFR60.42a(b)	D.8.
-sss	SJRPP Boiler #2	PM	Coal, Coal & Petcoke, or Fuel Oil	8760	0.30 lb/MMBtu			1,843.2	8,073.2	40CFR60.42a(a)1.	D.6.
	(6144 MMBtu/hr)										
	(conditions are for each boiler)										
	(boilers are identical)	% Ash	Fuel Oil		0.01%, by wt.			N/A	N/A	PSD-FL-010 and PA 81-13	D.7.
			Coal/Petcoke		0.18%, by wt.			N/A	N/A		
		SO_2	Coal	8760	1.2 lbs/MMBtu			7,372.8	32,292.9	40CFR60.43a(a)(1),(2)&(3)	D.9.
	Acid Rain Phase II Units		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.
	(297.5 MW Turbine-generator)		Oil & Coal/Petcoke		(340X + 520Y)/100					40CFR60.43a(h)(2)	D.14.
			Coal & Petcok	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		(130X + 260Y)/100					40CFR60.44a(c)	D.16.
			Coal & Petcok	8760	0.60 lb/MMBtu			3,686.4	16,146.4	40CFR60.44a(a)(1)&(2)	D.15.
		CO	All	8760	0.05 lb/MMBtu			307.2	1,345.5	PSD-FL-010 BACT	D.18.
			Coal & Petcoke		No significant increase compared to coal.					PSD-FL-010(B)	D.71.
		H_2SO_4 Mist	Coal & Petcoke		No significant increase compared to coal.					PSD-FL-010(B)	D.72.
-ttt	SJRPP Auxiliary Boiler #!	VE	#2 FO	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.406(1)	E.6.
-uuu	SJRPP Auxiliary Boiler #2	PM	#2 FO	8760	0.1 LB.MMBtu	12.7			55.6	PSD-FL-010	E.7.
	(127.0 MMBtu/hr - #2 FO)	SO_2	#2 FO	8760	0.8 lb/MMBtu	101.6			445.0	PSD-FL-010	E.8.
	(conditions are for each boiler)	SO_2-%S	#2 FO	8760	max. S content 0.76%, by wt.			106.2	465.0	PSD-FL-010	E.9.
	(boilers are identical)	% Ash	#2 FO		0.01%, by wt.			N/A	N/A	PSD-FL-010	E.10.

E. U. ID No.	Brief Description	Pollutant Name	Fuel(s)	Hours/ Year	Allowable Emissions Standard(s)	Allowable Emissions lbs/hr	Allowable Emissions TPY	Equivalent Emissions[1] lbs/hr	Equivalent Emissions[1] TPY	Regulatory Citation(s)	Permit Condition
-vvv	SJRPP Coal Storage Yard and Transfer Systems (all[6])	VE			≤10% Opacity			N/A	N/A	PSD-FL-010	F.6.
	Emissions Point[6]					Per Unit			Per Unit		
	#4	PM				1			4.4	PSD-FL-010	F.7.
	#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		
-www	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	G.6.
	Limestone Day Silos	VE			≤10% Opacity			N/A	N/A	PSD-FL-010	G.6.
		PM				0.05			0.2	PSD-FL-010	G.7.
	Flyash Day Silos & Handling Systems	VE			≤10% Opacity			N/A	N/A	PSD-FL-010	G.6.
		PM				0.2			0.9	PSD-FL-010	G.7.
	Limestone Hopper/Transfer Conveyors	VE			≤10% Opacity			N/A	N/A	PSD-FL-010	G.6.
		PM				0.65			2.8	PSD-FL-010	G.7.
	Limestone Unloading (Rail Dumper)	VE			≤10% Opacity			N/A	N/A	PSD-FL-010	G.6.
		PM				0.1			0.04	PSD-FL-010	G.7.
	Limestone Transfer Points	VE			≤10% Opacity			N/A	N/A	PSD-FL-010	G.6.
		PM				0.4			1.8	PSD-FL-010	G.7.
-xxx	SJRPP: Cooling Towers (2)	PM				67/each			293.5/each	PSD-FL-010	H.5.

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

[1] "Equivalent Emissions" listed are for informational purposes.

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

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

[4] Applies when the SO_2 CEMs is temporarily inoperative.

[5] Combustion turbines are identical emissions units.

[6] See the emissions points listed in Revised Table 6: PSD-FL-010, attached to the permit.

|electronic file name: 03100451.xls|

Table 2-1, Summary of Compliance Requirements

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

PROPOSED Permit No.: 0310045-001-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	Frequency Base Date [3]	Min. Compliance Test Duration	CMS [1,2]	See Permit Condition(s)
-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	
		PM	Fuel Oil	17, 5, 5B or 5F	Annual [4]	7/1 - 9/1	1 Hour	No	A.22. & A.27.
	Acid Rain Phase II Unit		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]	Annual [4]	7/1 - 9/1	1 Hour	Yes [2]	A.11., A.17., A.23.
		SO_2 -%S		or FS&A [6]	Annual [4]	7/1 - 9/1	1 Hour [7]	N/A	& A.24.
-002	NGS Boiler #2	VE	Fuel Oil	DEP Method 9	Semiannual	2/1 - 4/1	60 Minutes	No	A.20. & A.21.
	(On long-term reserve shutdown since 3/1/84.)		Natural Gas	DEP Method 9	N/A	2/1 - 4/1	60 Minutes	No	
		PM	Fuel Oil	17, 5, 5B or 5F	Semiannual	2/1 - 4/1	1 Hour	No	A.22. & A.27.
	Acid Rain Phase II Unit		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]	Semiannual	2/1 - 4/1	1 Hour	No	A.11., A.17., A.23.
		SO_2 -%S		or FS&A [6]	Semiannual	2/1 - 4/1	1 Hour [7]	N/A	& A.24.
-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	
		PM	Fuel Oil	17, 5, 5B or 5F	Annual [4]	5/1 - 7/1	1 Hour	No	A.22. & A.27.
	Acid Rain Phase II Unit		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]	Annual [4]	5/1 - 7/1	1 Hour	Yes [2]	A.11., A.17., A.23.
		SO_2 -%S		or FS&A [6]	Annual [4]	5/1 - 7/1	1 Hour [7]	N/A	& A.24.
		NO_X	Fuel Oil	7, 7A or 7E or	Annual [4]	5/1 - 7/1	1 Hour	Yes [1]	A.18.
				RATA	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								
-rrr	SJRPP Boiler #1	VE	All	9 and CMS	nnual [4] & Continuou	7/1 - 9/1	60 Minutes	Yes [1]	D.30. & D.41.
-sss	SJRPP Boiler #2	PM	All	19 & 5 or 5B	Annual [4]	7/1 - 9/1	1 Hour	No	D.41.
		SO_2	All	19 and CMS	nnual [4] & Continuou	7/1 - 9/1	1 Hour	Yes [1]	D.31. & D.42.
		NO_X	All	19 and CMS	nnual [4] & Continuou	7/1 - 9/1	1 Hour	Yes [1]	D.32. & D.43.
	Acid Rain Phase II Units	CO	Coal & Petcoke	10	Annual [4]	7/1 - 9/1	1 Hour	No	D.45. & D.71.
		H_2SO_4 Mist	Coal & Petcoke	8	Annual [4]	7/1 - 9/1	1 Hour	No	D.72.
-ttt	SJRPP Auxiliary Boiler #1	VE	No. 2 F.O.	DEP Method 9	Annual [4]	9/1 - 11/1	60 Minutes	No	E.15. & E.16.
-uuu	SJRPP Auxiliary Boiler #2	PM	No. 2 F.O.	5	Annual [4]	9/1 - 11/1	60 Minutes	No	E.17.
		SO_2 -%S	No. 2 F.O.	Fuel Sampling & Analysis Provided By Vendor				No	E.9., E.17. & E.18.
		% Ash	No. 2 F.O.	Fuel Sampling & Analysis Provided By Vendor				No	E.10. & E.19.
-vvv	SJRPP Coal Storage Yard and Transfer Systems	VE	N/A	9	Annual	7/1 - 9/1	60 Minutes	No	F.11.
		PM	N/A	5	Annual	7/1 - 9/1	1 Hour	No	F.12.
-www	SJRPP Limestone and Flyash Handling	VE	N/A	9	Annual	7/1 - 9/1	60 Minutes	No	G.11.
		PM	N/A	5	Annual	7/1 - 9/1	1 Hour	No	G.12.
-xxx	SJRPP Cooling Towers	PM	No mass emissions test is required since there are no stacks associated with this activity.					N/A	H.5.

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 firing fuel oil in years that fuel oil is fired less than 400 hours.

[5] RATA can be used as a formal compliance test for SO_2 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 ,equired once every 5 years, during the year prior to permit renewal.

[9] All test methods are EPA Methods unless stated.

[electronic file name: 03100452.xls]

Best Available Control Technology (BACT) Determination
Jacksonville Electric Authority
Duval County

The applicant plans to install an auxiliary fossil-fuel-fired steam generator at the Northside generating station. The proposed unit will have a design heat input of 116.5 million Btu/hr and fire residual or distillate oil. The primary function of this unit will be to supply inplant steam requirements, especially during the colder months of the year, and will not be used as a peaking unit.

The proposed auxiliary boiler will operate only when one or more of the larger steam generating units is down or in the startup mode, therefore there will be no additional increase in sulfur dioxide or particulate emissions to the atmosphere.

The boiler will be located within the area of influence of the Jacksonville particulate nonattainment area (Rule 17-2.410(2)2.).

BACT Determination Requested by the Applicant:

The particulate and sulfur dioxide emissions will be 0.1 and 1.98 pounds per million Btu of heat input, respectively. The proposed steam generator will operate only when one of the larger main units is down or in a startup mode.

Date of Receipt of a BACT application:

April 24, 1984

Date of Publication in the Florida Administrative Weekly:

May 4, 1984

Review Group Members:

The determination was based upon comments received from the New Source Review Section, Air Modeling Section and Jacksonville Division of Bio-Environmental Services.

BACT Determined by DER:

Particulate and sulfur dioxide emissions to be limited by the following two permit conditions:

1. This steam generating unit shall be used only as an auxiliary system and shall fire New [1] or New oil blended with internally generated waste oil [2], and having a sulfur content, by weight, not to exceed 1.8% as determined by ASTM method D-219.

2. The auxiliary steam generating unit shall be operational when one of the three larger (+ 2000-E6 Btu/hr) steam generating units has been shut down or in the start-up mode of operation prior to being put on line.

[1] The term "new" means an oil which has been refined from crude oil and has not been used, and which may or may not contain additives.

[2] 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 and, 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 (zero percent) polychlorinated biphenyls (PCBs).

Compliance shall be determined by requiring that whenever a main steam generator is down, the inactive source, NS #1, NS #2, or NS #3, is to be recorded in the auxiliary steam generator operating log. When electrical power demand requires all three main units to be on line, the total station residual fuel consumption will be recorded for each four hour period whenever the auxiliary steam generator is operating. The total station fuel consumption must not exceed 1,440,000 pounds in any consecutive three (3) hour period. The recorded fuel consumption data will be retained for at least two years.

Visible Emissions	Not to exceed 15% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

BACT Determination Rationale:

The applicant will shut down one of the larger +2000-E6 Btu/hr steam generators whenever the new 116.5-E6 unit is in operation or in startup mode. The new unit, therefore, would not increase particulate or sulfur dioxide emissions to the atmosphere. The applicant has proposed this scenario as BACT.

The applicant further contends that since the new boiler would only supply steam for inplant use, for example, to keep the generating station available for winter start-ups, this proposed BACT is reasonable.

The new boiler would:

1) operate below design capacity the majority of the time and only when one of the larger boilers is down or in start up mode

2) operate near design capacity primarily during the winter months, when electric power demand is low, and the main units are on standby

3) have installed state-of-the-art combustion controllers to minimize NO_x emissions, and

4) result in emissions considered minor as compared to the main units.

The department agrees that operation of the auxiliary boiler as per the proposed scenario is BACT. Particulate and sulfur dioxide emissions, when firing fuel oil, are related to the fuel sulfur content. Fuel oil containing less than 1.5% sulfur, by weight, is a SO_2 control option for a boiler of this size. The main units fire 1.8% sulfur content oil and the department does not believe a requirement for separate fuel oil storage for a lower sulfur content fuel is justified.

The fuel sulfur content was determined to be the BACT to control particulate matter and SO_2 emissions for the following reasons.

A. The cover letter attached to JEA's air permit application stated, "No. 6 fuel oil, less than 1.8% sulfur, is the only fuel presently available for boiler operation at the Northside station." (emphasis added). JEA has not submitted data indicating a higher sulfur content fuel will be fired.

B. The BACT economic review indicated that low sulfur fuel, as a method to control SO_2 emissions, was the cheaper alternative for a boiler of this size when compared to various wet or dry FGD systems.

C. Compliance with the permit conditions will require the taking of a spot fuel sample and the sulfur content determined by ASTM analysis Method D-219 at a cost of approximately $50. The energy basis SO_2 standard requested by JEA would require a stack test. A normal test probe could not be used due to the low gas velocity in the stack (less than 10 FPS) and special stack testing procedures would have to be used. The cost would be much greater than a fuel sample analysis.

D. A fuel oil sample can be obtained quickly and easily. Compliance can be determined at any time without elaborate preparations and at a reasonable cost.

As mentioned in the overview, a BACT determination is required as set forth in Rule 17-2.600(6). Rule 17-2.100(23) requires a visible emission limit in all BACT determinations. Since the 15% opacity limit is more stringent than the 20% in Rule 17-2.600(6)(a), the more stringent limit applies.

The visible emissions limit of 15% opacity is based on actual field observation of steam generators of this size when firing No. 6 oil. JEA has not submitted any data indicating why the proposed steam generators could not meet the 15% opacity limit.

Air modeling indicates the proposed source, operating as per the scenario determined as BACT, will not impact the nonattainment area, therefore only a BACT determination is required for this source as set forth in the Florida Administrative Code Rule 17-2.600(6) - Emission Limiting and Performance Standards.

The "new" oil requirement disallows the use of waste oil which could contain sham blended RCRA compounds, or other non-fossil fuels, emissions from which were not considered in this BACT analaysis.

<u>Details of the Analysis may be Obtained by Contacting:</u>

Edward Palagyi, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32301

Recommended By:

CH Fancy

C. H. Fancy, Deputy Bureau Chief

Date: 10/15/84

Approved:

Terry Cole for

Victoria J. Tschinkel, Secretary

Date: 10/15/84

Best Available Control Technology (BACT) Determination

Jacksonville Electric Authority

Duval County

The proposed facility is the construction of two 600 megawatt coal-fired electric utility steam generating units to be located in Jacksonville, Florida. The units will be designed for possible conversion to oil, gas or refuse firing. There will be an oil fired auxiliary boiler rated at 200 million Btu/hr estimated to have an annual capacity factor of 5 percent compared to 74 percent for the two units.

The plant will be located in Duval County which is classified nonattainment for the pollutant Ozone (17-2.16(1)(c) F.A.C.). It will be located in the area of influence of the Jacksonville particulate nonattainment area (17-2.13(1)(b) F.A.C.), however, the plant will not significantly impact the nonattainment area and is therefore exempt from the requirements of Section 17-2, 17 & 18 & 19 with respect to particulate emissions. The facility must comply with the provisions of 17-2.04 F.A.C. (Prevention of Significant Deterioration).

<u>BACT Determination Requested by the Applicant:</u>

Pollutant	Emission Limit
Particulates	0.03 lb/million Btu input
SO_2	0.76 lb/million Btu input
NO_x	0.60 lb/million Btu input
CO	0.05 lb/million Btu input

Particulate emissions to be controlled using an Electrostatic Precipitator (ESP). SO_2 emissions to be controlled with a limestone wet scrubbing system. There is no specific control technology for control of NO_x and CO emissions. BACT to be manufacturer's guarantee for state-of-the-art burner design parameters to minimize emissions.

Flyash emissions to be controlled using a pneumatic transfer system and bottom ash using a wet transfer system. Emissions from coal and limestone handling to be controlled by use of enclosed conveying systems with baghouses rated at 99.9 percent efficiency. Water suppression to control dust to be used as required.

Date of Receipt of a Complete BACT Application:

February 27, 1981

Date of Publication in the Florida Administrative Weekly:

March 27, 1981

Review Group Members:

Steve Pace, Jacksonville Bio-Environmental Services
Johnny Cole, DER, St. Johns River Subdistrict
Buck Oven Power Plant Siting Section
Bob King, DER, Bureau of Air Quality Management
Tom Rogers, DER, Air Modeling Section

Bio-Environmental Services recommended a 65% reduction in NO_x emissions, or 0.5 lb/million Btu heat input. This was the only exception to unanimous acceptance of the NSPS emission limits as BACT.

BACT Determination by DER:

Pollutant	Emission Limit
Particulates	0.03 lb/million Btu input
SO_2	0.76 lb/million Btu input
NO_x	0.60 lb/million Btu input
CO	0.05 lb/million Btu input

Justification of DER Determination:

NSPS, Subpart Da, Standards of performance for electric utility steam generating units for which construction is commenced after September 18, 1978, is determined as BACT for the proposed project. The proposed control equipment is state-of-the-art and determined as BACT.

Emissions from the auxiliary boiler are minor compared to the main units. The auxiliary boiler will operate only when one of the main units is not in operation. Limited operation of the auxiliary boiler is determined as BACT.

Details of the Analysis May be Obtained by Contacting:

Edward Palagyi, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32301

Page Three

Recommended By:

C H [signature]

for Steve Smallwood, Chief, BAQM

Date:

5/6/81

Approved:

Victoria Tschinkel [signature]

Victoria Tschinkel, Secretary

Date:

5/7/81

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

Notice of Final Permit Amendment

In the Matter of an
Application for Permit Amendment

DEP File No. PSD-FL-010(B)

Mr. Richard Breitmoser, P.E.
Environmental Health & Safety Group
St. Johns River Power Park
11201 New Berlin Road
Jacksonville, Florida 32226

Enclosed is a letter that amends Permit Number PSD-FL-010(B). This letter amends the specific conditions related to sulfur dioxide (SO_2) emissions and fuel use in the subject Final Determination (dated March 12, 1982) pursuant to 40 CFR 52.21-Prevention of Significant Deterioration (PSD permit). This permit amendment is issued pursuant to Section 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 14 (fourteen) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

A. A. Linero, P.E. 10/11 for
C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT AMENDMENT (including the FINAL permit amendment) was sent by certified mail (*) and copies were mailed by U.S. mail before the close of business on 10-14-96 to the person(s) listed:

Mr. Richard Breitmoser*

Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Hamilton Oven, DEP
Mr. Chris Kirts, NED
Mr. Jim Manning, RESD
Mr. Ken Kosky, MKBN

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kim Tober 10-14-96
(Clerk) (Date)

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

October 11, 1996

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Richard Breitmoser, P.E.
Vice President
Environmental Health and Safety Group
St. Johns River Power Park
11201 New Berlin Road
Jacksonville, Florida 32226

Dear Mr. Breitmoser:

Re: Permit Amendment - Petroleum Coke Cofiring
Jacksonville Electric Authority, St. Johns River Power Park
PSD-FL-010(B); Duval County

The Department hereby amends the specific conditions related to sulfur dioxide (SO_2) emissions and fuel use in the subject Final Determination (dated March 12, 1982) pursuant to 40 CFR 52.21 - Prevention of Significant Deterioration (PSD Permit). The PSD Permit, previously amended on March 30, 1995 is amended as follows:

Condition 2.A. (new)

i. When blends of petroleum coke and coal with a sulfur content of up to or equal to 2 percent are fired in Units 1 or 2, the SO_2 emissions shall not exceed 0.55 pound per million British thermal units (lb/MMBtu) and a minimum of 76 percent reduction shall be achieved in the flue gas desulfurization system.

ii. When co-firing petroleum coke with coals having a sulfur content between 2.00 and 3.63 percent, the emission limitation shall be based on the following formula:

SO_2 emission limit (lb/MMBtu) = (0.2 x C/100) + 4

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

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

Mr. Richard Breitmoser
October 11, 1996
Page Two

iii. When coals with a sulfur content greater than 3.63 percent are co-fired with petroleum coke, the SO_2 emissions shall not exceed the following formula:

$$SO_2 \text{ (lb/MMBtu)} = (0.1653 \times C \times S - 0.4 \times [C + 40]) \times 1/100$$

where: C = percent of coal co-fired on a heat input basis
S = weight percent sulfur in the coal

iv. The maximum SO_2 emission rate when firing petroleum coke and coal shall not exceed 0.676 lb/MMBtu.

v. Compliance with the SO_2 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 New Source Performance Standards (NSPS) codified in 40 CFR 60 Subpart Da, except as noted above.

Condition 2.B. (new)

The petroleum coke-coal blends shall be limited to a maximum of 20 percent petroleum coke, by weight. The maximum weight of the petroleum coke burned shall not exceed 100,000 lb/hr. The maximum sulfur content of the petroleum coke-coal blend shall not exceed 4.00 percent, by weight.

Condition 3. A. (new)

The applicant shall maintain and submit to the Department on an annual basis for a period of five years from the date the unit is initially co-fired with petroleum coke, information demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational changes did not result in emissions increases of nitrogen oxides and particulate matter.

Condition 3. B. (new)

The applicant shall maintain and submit to the Department on a semiannual basis for a period of two years from the date the unit is initially co-fired with 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 emission monitoring data for carbon monoxide emissions shall be submitted to the Department for a period of two years to show the range of emissions experienced during each quarter.

Condition 3. C. (new)

The applicant shall maintain and submit to the Department on a semiannual basis for a period of two years from the date the unit is initially co-fired with petroleum coke, information demonstrating that the operational changes did not result in significant emissions increases of sulfuric acid mist. The sulfuric acid mist emissions shall be based on test results using EPA Method 8.

A copy of this amendment letter shall be attached to and shall become a part of Permit PSD-FL-010.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L. Rhodes

Howard L. Rhodes, Director
Division Air Resources Management

JACKSONVILLE ELECTRIC AUTHORITY

OPERATION AND MAINTENANCE PLAN

In compliance with Section 17-2.650(2)(g)4. of the Florida Administrative Code, the Jacksonville Electric Authority submits its "Operation and Maintenance Plan", to be appended where appropriate to unit operating permits.

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 non-attainment area. These schedules apply to each on-line unit.

Daily:

1. Clean one deck of burners (renew tips as necessary).
2. Conduct one complete soot-blowing cycle (or as needed).
3. Maintain optimum fuel oil temperature and pressure.

Weekly:

1. Clean fuel oil strainers (more frequently if required).

Annually:

1. Clean the boiler and inspect baffles.
2. Inspect the: (a) wind box;
   (b) registers;
   (c) diffusers;
   (d) refractory throat.
3. Adjust the air registers for optimum flame pattern (more frequently if required).
4. Replace burner tips (more frequently if required).

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. Number of burners in service.
3. Burner oil pressure.
4. 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 two years.

BEST AVAILABLE COPY

Phase II Permit Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: [X] New [ ] Revised

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

Plant Name	State	ORIS Code
Northside Generating Station	FL	667

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

a	b	c	d	e
	Compliance Plan			
Boiler ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
1	Yes			
2	Yes			
3	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

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

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

Plant Name (from Step 1)

BEST AVAILABLE COPY

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

Standard Requirements

Permit Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Recordkeeping and Reporting Requirements (cont.)

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

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

Liability.

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

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

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

Certification

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

Name Brian M. Wirz	
Signature	Date 12/14/95

STEP 5 (optional)
Enter the source AIRS and FINDS identification numbers, if known

AIRS	
FINDS	

BEST AVAILABLE COPY

Phase II Permit Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: [X] New [ ] Revised

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

Plant Name	State	ORIS Code
St. Johns River Power Park	FL	207

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

a	b	c	d	e
	Compliance Plan			
Boiler ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
1	Yes			
2	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

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

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

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

Standard Requirements

Permit Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Plant Name (from Step 1)

Recordkeeping and Reporting Requirements (cont.)

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

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

Liability.

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

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

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

Certification

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

Name Brian M. Wirz	
Signature	Date 12/14/95

STEP 5 (optional)
Enter the source AIRS and FINDS Identification numbers, if known

AIRS
FINDS

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 O_2 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]

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

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

ORDER EXTENDING PERMIT EXPIRATION DATE

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

Section 403.0872(2)(b), Florida Statutes (F.S.), specifies that any facility which submits to the Department of Environmental Protection (Department) a timely and complete application for a Title V permit "is entitled to operate in compliance with its existing air permit pending the conclusion of proceedings associated with its application."

Section 403.0872(6), F.S., provides that a proposed Title V permit which is not objected to by the United States Environmental Protection Agency (EPA) "must become final no later than fifty-five (55) days after the date on which the proposed permit was mailed" to the EPA.

Pursuant to the Federal Acid Rain Program as defined in rule 62-210.200, Florida Administrative Code (F.A.C.), all Acid Rain permitting must become effective on January 1 of a given year.

This facility which will be permitted pursuant to section 403.0872, F.S., (Title V permit) will be required to have a permit effective date subsequent to the final processing date of the facility's Title V permit.

To prevent misunderstanding and to assure that the above identified facility continues to comply with existing permit terms and conditions until its Title V permit becomes effective, it is necessary to extend the expiration date(s) of its existing valid permit(s) until the effective date of its Title V permit. Therefore, under the authority granted to the Department by section 403.061(8), F.S., **IT IS ORDERED:**

1. The expiration date(s) of the existing valid permit(s) under which the above identified facility is currently operating is (are) hereby extended until the effective date of its permit issued pursuant to section 403.0872, F.S., (Title V permit);
2. The facility shall comply with all terms and conditions of its existing valid permit(s) until the effective date of its Title V permit;
3. The facility will continue to comply with the requirements of Chapter 62-214, F.A.C., and the Federal Acid Rain Program, as defined in rule 62-210.200, F.A.C., pending final issuance of its Title V permit.

PETITION FOR ADMINISTRATIVE REVIEW

The Department will take the action described in this Order unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 of the Florida Statutes (F.S.). Mediation under Section 120.573, F.S., will not be available for this proposed action.

A person whose substantial interests are affected by the Department's proposed decision may petition for an administrative hearing in accordance with sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. Petitions must be filed within 21 days of receipt of this Order. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 of the Florida Statutes, or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information:

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department File Number, and the county in which the project is proposed;

(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;

(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;

(d) A statement of the material facts disputed by the petitioner, if any;

(e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action;

(f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and

(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the action or proposed action addressed in this notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this Order. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under section 120.542 of the Florida Statutes. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. The petition must specify the following information:

(a) The name, address, and telephone number of the petitioner;

(b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any;

(c) Each rule or portion of a rule from which a variance or waiver is requested;

(d) The citation to the statute underlying (implemented by) the rule identified in (c) above;

(e) The type of action requested;

(f) The specific facts that would justify a variance or waiver for the petitioner;

(g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and

(h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in section 120.542(2) of the Florida Statutes, and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This Order constitutes final agency action unless a petition is filed in accordance with the above paragraphs.

RIGHT TO APPEAL

Any party to this Order has the right to seek judicial review of the Order pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000; and, by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date the Notice of Agency Action is filed with the Clerk of the Department.

DONE AND ORDERED this 13 day of Nov, 1997 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L Rhodes

HOWARD L. RHODES, Director
Division of Air Resources Management
Twin Towers Office Building
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
850/488-0114

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order and all copies were sent by certified mail before the close of business on 11/17/97 to the person(s) listed:

Mr. Walter P. Brussels, Managing Director/Responsible Official, JEA
Mr. Jon P. Eckenbach, Executive Vice President/Designated Representative, JEA
Mr. Bert Gianazza, JEA, Application Contact
Mr. James L. Manning, AWQD

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency Clerk, receipt of which is hereby acknowledged.

Barbara J. Boutwell 11/17/97
(Clerk) (Date)