Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

March 11, 1999

Mr. A.K. Sharma
Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

Re: PROPOSED Title V Permit No.: 0970043-002-AV
Cane Island Power Park

Dear Mr. Sharma:

One copy of the "PROPOSED PERMIT DETERMINATION" for the Cane Island Power Park located at 6075 Old Tampa Hwy, Intercession City, Osceola County, is enclosed. This letter is only a courtesy to inform you that the DRAFT permit has become a PROPOSED permit.

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

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permit will not be issued until the permitting authority receives written notice that the objection is resolved or withdrawn.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 Michael P. Halpin, P.E. at 850/921-9530.

Sincerely,

CH Fancy

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

CHF/h

Enclosures

3/18/99 cc: Reading File
Mike Halpin

copy furnished to:
Mr. D. D. Schultz, P.E., Black & Veatch
Mr. Timothy M. Hillman, Black & Veatch
Mr. Len Kozlov, CD
Ms. Gracy R. Danois, USEPA, Region 4 (INTERNET E-mail Memorandum)
Ms. Carla E. Pierce, USEPA, Region 4 (INTERNET E-mail Memorandum)

Is your RETURN ADDRESS completed on the reverse side?

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

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. D. D. Schultz, P.E.
Black & Veatch
8400 Ward Parkway
Kansas City, MO 64114-2031

4a. Article Number
P 263 585 196

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

7. Date of Delivery
3/23/99

5. Received By: (Print Name)
C Wyancko

6. Signature: (Addressee or Agent)
X

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

PS Form **3811**, December 1994 102595-97-B-0179 Domestic 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, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. A.K. Sharma
Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

4a. Article Number
P 263 585 195

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

7. Date of Delivery
3/22/99

5. Received By: (Print Name)

6. Signature: (Addressee or Agent)
X

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

PS Form 3811, December 1994 Domestic Return Receipt

Thank you for using Return Receipt Service.

P 263 585 196

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

Sent to: Mr. D. D. Schultz, P.E.	
Street & Number: 8400 Ward Parkway	
Post Office, State, & ZIP Code: Kansas City, MO 64114-2031	
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: 3/18/99 KUA - Cane Island PROPOSED-Facility ID#0970043	

PS Form **3800**, April 1995

P 263 585 195

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

Sent to: Mr. A.K. Sharma	
Street & Number: 1701 West Carroll Street	
Post Office, State, & ZIP Code: Kissimmee, Florida 34741	
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: 3/18/99 KUA - Cane Island PROPOSED-Facility ID0970043	

PS Form **3800**, April 1995

Is your **RETURN ADDRESS** completed on the reverse side?

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

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Timothy M. Hillman
Black & Veatch
8400 Ward Parkway
Kansas City, MO 64114-2031

4a. Article Number
P 263 585 197

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

7. Date of Delivery
3/23/99

5. Received By: (*Print Name*)
C Yancko

6. Signature: (*Addressee or Agent*)
X

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

PS Form **3811**, December 1994 102595-97-B-0179 **Domestic Return Rec**

'ou for using Return Receipt Service.

Is your **RETURN ADDRESS** completed on the reverse side?

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

... to receive the ... services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Len Kozlov
Central District Office
3319 Maguire Boulevard
Suite 232
Orlando, Florida 32803-3767

4a. Article Number
P 263 585 198

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

7. Date of Delivery
MAR 22 1999

5. Received By: (*Print Name*)

6. Signature: (*Addressee or Agent*)
X

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

PS Form **3811**, ... **Domestic Return Receipt**

Thank you for using Return Receipt Service.

P 263 585 197

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

Sent to Mr. Timothy M. Hillman	
Street & Number 8400 Ward Parkway	
Post Office, State, & ZIP Code Kansas City, MO 64114-2031	
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 3/18/99 KUA - Cane Island PROPOSED-Facility ID0970043	

PS Form **3800**, April 1995

P 263 585 198

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

Sent to Mr. Len Kozlov	
Street & Number 3319 Maguire Blvd., Ste. 232	
Post Office, State, & ZIP Code Orlando, Florida 32803-3767	
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 3/18/99 KUA - Cane Island PROPOSED-Facility ID0970043	

PS Form **3800**, April 1995

I. Public Notice.

An "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" to Kissimmee Utility Authority for the Cane Island Power Park located at 6075 Old Tampa Hwy, Intercession City, Osceola County was clerked on October 13, 1998. The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was published in the Osceola Sentinel on October 16, 1998. The DRAFT Title V Air Operation Permit was available for public inspection at the permitting authority's office in Orlando. Proof of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was received on October 23, 1998.

II. Public Comment(s).

A. The only comments received were from Kissimmee Utility Authority in a letter from Mr. A.K. Sharma dated December 30, 1998 and received on January 6, 1999. This letter is on file with the permitting authority. All comments were considered to be acceptable and are incorporated as follows:

1. Comment on page numbering:

Response: The page numbering has been corrected.

2. Comment on Page 4 of 31, Condition 4:

Response: Since the current wording is acceptable, it will be left as is

3. Comment on Page 8 of 28, Condition A.5.:

As a result of this comment, Condition A.5. is hereby changed:

From:

A.5. The maximum allowable emissions from Unit 1 shall not exceed the emission limitations listed below.

Pollutant	**Emission Limits**			**Basis**
	Gas	**Number 2 Fuel Oil**	**Tons/Year** [a, b]	
NO_x [c]	15 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	106.61	BACT
SO_2	nil	20 lb/hr	5.0	BACT
PM	0.0245lb/mmBtu	0.0323 lb/mmBtu	40.13	BACT
H_2SO_4	nil	2.2 lb/hr	0.55	BACT
VOC	1.4 lb/hr	3 lb/hr	6.55	BACT
CO	30 ppmvd	63 ppmvd	184.2	BACT
Opacity	10% (see A.4.)	10% (see A.4.)		BACT
Be	nil	2.5e-6 lb/mmBtu	< 1	BACT
As	nil	4.2e-6 lb/mmBtu	< 1	AC 49-205703
Hg	nil	3.1e-6 lb/mmBtu	< 1	AC 49-205703
Pb	nil	2.8e-5 lb/mmBtu	< 1	AC 49-205703

a. Tons per year based on 8260 hrs/yr for natural gas firing, 500 hrs/yr for number 2 fuel oil firing.
b. Based on 372 mmBtu/hr for number 2 fuel oil and 367 mmBtu/hr for natural gas.
c. NO_x emission limits were permitted to be 25 ppmvd while firing natural gas until 1/1/98 via original application. An amendment to permit (AC0970043-003) was made on 5/19/97 extending the date for the reduced NO_x emission limit of 15 ppmvd until 1/1/99.

To:

A.5. The maximum allowable emissions from Unit 1 shall not exceed the emission limitations listed below.

Pollutant	Emission Limits			Basis
	Gas	**Number 2 Fuel Oil**	**Equivalent Emissions Tons/Year** [a, b]	
NO_x [c]	25/15 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	116.9	BACT
SO_2	nil	20 lb/hr	10.0	BACT
PM	0.0245lb/mmBtu	0.0323 lb/mmBtu	40.9	BACT
H_2SO_4	nil	2.2 lb/hr	1.1	BACT
VOC	1.4 lb/hr	3 lb/hr	6.9	BACT
CO	30 ppmvd	63 ppmvd	193.2	BACT
Opacity	10% (see A.4.)	10% (see A.4.)		BACT
Be [d]	nil	2.5e-6 lb/mmBtu	< 1	BACT
As [d]	nil	4.2e-6 lb/mmBtu	< 1	AC 49-205703
Hg [d]	nil	3.1e-6 lb/mmBtu	< 1	AC 49-205703
Pb [d]	nil	2.8e-5 lb/mmBtu	< 1	AC 49-205703

a. Tons per year based on 7760 hrs/yr for natural gas firing, 1000 hrs/yr for number 2 fuel oil firing.
b. Based on 372 mmBtu/hr for number 2 fuel oil and 367 mmBtu/hr for natural gas.
c. NO_x emission limits were permitted to be 25 ppmvd while firing natural gas until 1/1/98 via original application. An amendment to permit (AC0970043-003) was made on 5/19/97 extending the date for the reduced NO_x emission limit of 15 ppmvd until 1/1/99. An additional extension was granted on December 15, 1998 via amendment AC0970043-005 further extending this date until 1/1/00.
d. Limits based upon an approved emission factor, which is subject to change in the future.

4. Comment on Page 9 of 28, Condition A.6.:

As a result of this comment Condition A.6. is hereby changed:

From:

A.6. Annual Compliance Tests. Emission testing for visible emissions NO_x shall be performed annually, in accordance with specific condition **A.8.**, with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NO_x.

If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
[Rules 62-297.401 and 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

To:

A.6. Annual Compliance Tests. Emission testing for visible emissions and NO_x shall be performed annually, in accordance with specific condition **A.8.**, with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NO_x.

If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
[Rules 62-297.401 and 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

5. Comment on Page 10 of 28, Condition A.11.:

As a result of this comment Condition A.11. is hereby changed:

From:

A.11 Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides in accordance with the requirements of 40 CFR 75. While water injection is being utilized for NO_x control, water to fuel ratio shall be continuously monitored.
[AC 49-205703 (PSD-FL-182)]

To:

A.11 Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides in accordance with the requirements of 40 CFR 75. While water injection is being utilized for NO_x control, water to fuel ratio and fuel bound nitrogen is not required to be continuously monitored as long as the permittee will report excess emissions using the data collected by the continuous monitoring system in accordance with the following conditions:

1. Each NO_x CEMS must be capable of calculating NO_x emissions concentrations corrected to 15% O2 and ISO conditions.
2. Monitor data availability shall be no less than 95 percent on a quarterly basis.
3. NO_x CEMS should provide at least 4 data points for each hour and calculate a one-hour average.

To implement condition 1, KUA shall use ambient data (temperature, relative humidity, pressure) to correct excess emissions data to ISO conditions if requested by the Department. If monitor availability drops below 95% on a quarterly basis as prescribed in condition 2, KUA shall use water to fuel ratio and fuel-bound nitrogen data to monitor excess emissions in subsequent quarters until the minimum CEMS monitor availability is above 95%. The use of CEMS to monitor excess emissions is more stringent than the surrogate parameter monitoring in 40 CFR 60.334 since the CEMS directly measures NO_x emissions. The CEMS also provides monitoring when no water injection is used to control NOx emissions (i.e., when firing natural gas, dry low NO_x burners are used).
[AC 49-205703 (PSD-FL-182)]

6. Comment on page 10 of 28, Condition A.13.:

As a result of this comment Condition A.13. is hereby changed:

From:

A.13. Excess Emission Reports. Quarterly excess emission reports shall be submitted to the DEP's Central District Office. These reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.
[AC 49-205703 (PSD-FL-182)]

To:

A.13. Excess Emission Reports. Semi-annual excess emission reports shall be submitted to the DEP's Central District Office. These reports shall be postmarked by the 30th day following the end of each calendar half. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.
[AC 49-205703 (PSD-FL-182)]

7. Comment on Page 13 of 28, Condition B.5.:

As a result of this comment Condition B.5. is hereby changed:

From:

B.5. The maximum allowable emissions from Unit 2 shall not exceed the emission limitations listed below.

Pollutant	Emission Limits			Basis
	Gas	Number 2 Fuel Oil	Tons/Year [a, b]	
NO_x [c]	15 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	262	BACT
SO_2	nil	52 lb/hr	13	BACT
PM	0.010 lb/mmBtu	0.0162 lb/mmBtu	40.13	BACT
H_2SO_4	nil	5.72 lb/hr	1.4	BACT
VOC	2 lb/hr	5 lb/hr	9.6	BACT
CO	20 ppmvd	20 ppmvd	239	BACT
Opacity	10% (see B.4.)	10% (see B.4.)		BACT
Be	nil	2.5e-6 lb/mmBtu	< 1	BACT
As	nil	4.2e-6 lb/mmBtu	< 1	AC 49-205703
Hg	nil	3.0e-6 lb/mmBtu	< 1	AC 49-205703
Pb	nil	2.8e-5 lb/mmBtu	< 1	AC 49-205703

a. Tons per year based on 8260 hrs/yr for natural gas firing, 500 hrs/yr for number 2 fuel oil firing.
b. Based on 928 mmBtu/hr for number 2 fuel oil and 869 mmBtu/hr for natural gas.
c. NO_x emission limits were permitted to be 25 ppmvd while firing natural gas until 1/1/98 via original application.

To:

B.5. The maximum allowable emissions from Unit 2 shall not exceed the emission limitations listed below.

Pollutant	Emission Limits			Basis
	Gas	Number 2 Fuel Oil	Equivalent Emissions Tons/Year [a, b]	
NO_x [c]	15 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	290.6	BACT
SO_2	nil	52 lb/hr	26	BACT
PM	0.010 lb/mmBtu	0.0162 lb/mmBtu	41.2	BACT
H_2SO_4	nil	5.72 lb/hr	2.86	BACT
VOC	2 lb/hr	5 lb/hr	10.26	BACT
CO	20 ppmvd	20 ppmvd	242	BACT
Opacity	10% (see B.4.)	10% (see B.4.)		BACT
Be [d]	nil	2.5e-6 lb/mmBtu	< 1	BACT
As [d]	nil	4.2e-6 lb/mmBtu	< 1	AC 49-205703
Hg [d]	nil	3.0e-6 lb/mmBtu	< 1	AC 49-205703
Pb [d]	nil	2.8e-5 lb/mmBtu	< 1	AC 49-205703

a. Tons per year based on 7760 hrs/yr for natural gas firing, 1000 hrs/yr for number 2 fuel oil firing.
b. Based on 928 mmBtu/hr for number 2 fuel oil and 869 mmBtu/hr for natural gas.NO_x emission limits were permitted to be 25 ppmvd while firing natural gas until 1/1/98 via original application.
c. Limits based upon an approved emission factor, which is subject to change in the future.
d. Limits based upon an approved emission factor, which is subject to change in the future.

8. Comment on Page 14 of 28, Condition B.6.:

As a result of this comment Condition B.6. is hereby changed:

From:

B.6. Annual Compliance Tests. Emission testing for visible emissions NO_x shall be performed annually, in accordance with specific condition **B.8.**, with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NO_x.

If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
[Rules 62-297.401 and 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

To:

B.6. Annual Compliance Tests. Emission testing for visible emissions and NO_x shall be performed annually, in accordance with specific condition **B.8.**, with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NO_x.

If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
[Rules 62-297.401 and 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

9. Comment on Page 15 of 28, Condition B.11.:

As a result of this comment Condition B.11. is hereby changed:

From:

B.11. Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides in accordance with the requirements of 40 CFR 75. While water injection is being utilized for NO_x control, water to fuel ratio shall be continuously monitored.
[AC 49-205703 (PSD-FL-182)]

To:

B.11 Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides in accordance with the requirements of 40 CFR 75. While water injection is being utilized for NO_x control, water to fuel ratio and fuel bound nitrogen is not required to be continuously monitored as long as the permittee will report excess emissions using the data collected by the continuous monitoring system in accordance with the following conditions:

1. Each NO_x CEMS must be capable of calculating NO_x emissions concentrations corrected to 15% O2 and ISO conditions.
2. Monitor data availability shall be no less than 95 percent on a quarterly basis.
3. NO_x CEMS should provide at least 4 data points for each hour and calculate a one-hour average.

To implement condition 1, KUA shall use ambient data (temperature, relative humidity, pressure) to correct excess emissions data to ISO conditions if requested by the Department. If monitor availability drops below 95% on a quarterly basis as prescribed in condition 2, KUA shall use water to fuel ratio and fuel-bound nitrogen data to monitor excess emissions in subsequent quarters until the minimum CEMS monitor availability is above 95%. The use of CEMS to monitor excess emissions is more stringent than the surrogate parameter monitoring in 40 CFR 60.334 since the CEMS directly measures NO_x emissions. The CEMS also provides monitoring when no water injection is used to control NOx emissions (i.e., when firing natural gas, dry low NO_x burners are used).
[AC 49-205703 (PSD-FL-182)]

10. Comment on Appendix S, Table 1-1 (Footnote "a") for both emission units:

As a result of this comment, the footnotes are hereby changed:

From:

a lb/hour and TPY values based on using number 2 fuel oil for 1000 hours per year; for natural gas using 8760 hours per year.

To:

a lb/hour and TPY values based on using number 2 fuel oil for 1000 hours per year; for natural gas using 7760 hours per year.

11. Comment on Appendix S, Table 2-1 for both emission units:

As a result of this comment Table 2-1 for both emission units are hereby changed:

From:
Testing Frequency - Annual

To: Testing Frequency - Initial Compliance

The enclosed PROPOSED Title V Air Operation Permit includes the aforementioned changes to the DRAFT Title V Air Operation Permit.

III. Conclusion.

The permitting authority hereby issues the PROPOSED Permit No.: 0970043-002-AV, with changes noted above.

Because of the number of changes to the DRAFT, a copy of the PROPOSED permit has been printed for the applicant.

STATEMENT OF BASIS

Kissimmee Utility Authority
Cane Island Power Park
Facility ID No.: 0970043
Osceola County

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0970043-002-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 two fossil fuel fired combustion turbine electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2). Unit No. 1 consists of a General Electric LM-6000PA combustion turbine which drives a generator with a nominal rating of 40 Megawatts. This is a simple cycle unit. Unit No. 2 consists of a General Electric PG7111(EA) combustion turbine and an unfired heat recovery steam generator (HRSG). The combustion turbine is rated at 80MW whereas the steam turbine/generator is rated at 40MW, providing for an overall unit nominal rating of 120 Megawatts. This combined cycle unit is routinely referred to as a GE-7EA. Each combustion turbine fires natural gas as the primary fuel with very low sulfur #2 oil (.05%) as a backup. Each unit has its individual stack.

Simple Cycle Combustion Turbine (Unit No. 1) is fired primarily on natural gas and secondarily on No. 2 fuel oil. Limitations exist on both the sulfur content of the oil and the annual hours for firing oil. This unit, as permitted herein, has a maximum heat input of 367 MMBtu per hour while firing natural gas and 372 MMBtu per hour while firing #2 fuel oil.

Combined Cycle Combustion Turbine (Unit No. 2) is fired primarily on natural gas and secondarily on No. 2 fuel oil. Limitations exist on both the sulfur content of the oil and the annual hours for firing oil. This unit, as permitted herein, has a maximum heat input of 869 MMBtu per hour while firing natural gas and 928 MMBtu per hour while firing #2 fuel oil.

Each unit has its own stack. Unit No. 1 has a 65 ft high stack whereas Unit No. 2 has a 75 ft high stack. Particulate matter, SO_2 and H_2SO_4 emissions generated during the operation of the units are controlled by combusting clean fuels. The control of NO_x is achieved through the use of water injection and low-NO_x combustion technology.

Each combustion turbine, units #1 and #2 are regulated under the federal Acid Rain Program, adopted and incorporated by reference in Rule 62-204.800, F.A.C.; and NSPS-40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT). Combustion turbine no. 1 began commercial operation in 1994 and combustion turbine no. 2 began commercial operation in 1995.

The heat input limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 95 to 100 percent of the emissions unit's rated capacity (or to limit future operation to 105 percent of the test load), to establish appropriate emissions limits and to aid in determining future rule applicability. A note below the permitted capacity condition clarifies this. Regular record keeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required to demonstrate at what percentage of the rated capacity that the emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of process variables for emissions tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

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

Kissimmee Utility Authority
Cane Island Power Park
Facility ID No.: 0970043
Osceola County

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0970043-002-AV

<u>Permitting Authority:</u>
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

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0970043-002-AV

Table of Contents

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

Permittee:
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, FL 34741-6804

PROPOSED Permit No.: 0970043-002-AV
Facility ID No.: 0970043
SIC Nos.: 49
Project: Initial Title V Air Operation Permit

This permit is for the operation of the Kissimmee Utility Authority Cane Island Power Park. This facility is located at 6075 Old Tampa Hwy, Intercession City, Osceola County; UTM Coordinates: Zone 17; Latitude: 28 16' 40" North and Longitude: 81 31' 01" West.

STATEMENT OF BASIS: 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.

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Appendix TV-1, Title V Conditions (version dated 12/02/97)
Appendix SS-1, Stack Sampling Facilities (version dated 10/07/96)
Table 297.310-1, Calibration Schedule (version dated 10/07/96)
Figure 1 - Summary Report-Gaseous And Opacity Excess Emission And Monitoring System Performance Report (version dated 7/96)
Alternate Sampling Procedure: ASP Number 97-B-01
BACT Determination dated April 7, 1993

Effective Date: January 1, 2000
Renewal Application Due Date: July 5, 2004
Expiration Date: December 31, 2004

Howard L. Rhodes, Director
Division of Air Resource Management

HLR/sms/mh

Section I. Facility Information.

Subsection A. Facility Description.

This facility is an electric power generating plant and consists of:

Simple Cycle Combustion Turbine Unit 1 (Emissions Unit 001), rated at 40 MW;

Combined Cycle Combustion Turbine Unit 2 (Emissions Unit 002), rated at 120 MW;

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

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

The use of "Permitting Notes" throughout this Permit are for informational purposes only and are not permit conditions.

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

E.U. ID No.	Brief Description
001	Simple Cycle Combustion Turbine Unit 1, rated at 40 MW, 367 MMBtu/hr for natural gas and 372 MMBtu/hr for number 2 fuel oil, capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack .
002	Combined Cycle Combustion Turbine Unit 2, rated at 120 MW, 869 MMBtu/hr for natural gas and 928 MMBtu/hr for number 2 fuel oil, capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack .

Unregulated Emissions Units and/or Activities, See Appendix U-1	
003	Fuel oil, gasoline and lube oil storage tanks.
004	Fuel oil, gasoline and lube oil storage tanks.

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

Subsection C. Relevant Documents.

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

These documents are provided to the permittee for information purposes only:
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements

These documents are on file with the permitting authority:
Initial Title V Permit Application received June 14, 1996
Phase II Acid Rain Application/Compliance Plan received January 14, 1998.

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. The permittee 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.]

3. 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.]

4. 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].

5. 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.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6), and 62-4.040(1)(b), F.A.C.]

7. 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.]

8. Not Federally Enforceable. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

a. Maintenance of paved areas as needed.
b. Worker and site vehicle movements on paved roads.
c. Delivery vehicle movements on paved roads.
d. Fuel oil delivery by truck on paved roads.

[Rule 62-296.320(4)(c)2., F.A.C.; Proposed by applicant in the initial Title V permit application received June 14, 1996]

9. 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.]

10. The permittee shall submit all compliance related notifications and reports required of this permit (other than Acid Rain Program Information) to the Department's Central District office:

Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

Acid Rain Program Information shall be submitted, as necessary to:

Department of Environmental Protection
2600 Blair Stone Road
Mail Station #5510
Tallahassee, Florida 32399-2400
Telephone: 850/488-6140
Fax: 850/922-6979

and to:

United States Environmental Protection Agency, Region 4
Air Pesticides & Toxics Management Division
Acid Rain Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9102
Fax: 404/562-9095

11. Any reports, data, notifications, certifications, and requests (other than Acid Rain Program Information) 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

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

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit.

001	Simple Cycle Combustion Turbine Unit 1, rated at 40 MW, 367 MMBtu/hr for natural gas and 372 MMBtu/hr for number 2 fuel oil, capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack .

{Permitting note(s): This emissions unit is regulated under Acid Rain, Phase II; Rule 62-210.300, F.A.C., Permits Required; and, is subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. The affected facility to which this subpart applies is the simple cycle gas turbine, Unit 1. This unit underwent a BACT Determination dated April 7, 1993. BACT Limits were incorporated into the subsequent air construction/PSD permits including AC 49-205703 (PSD-FL-182). Exhaust is vented through a 65 ft. stack. NO_x emissions are controlled by low-NO_x combustors, and by water injection, whereas SO_2 and H_2SO_4 emissions are controlled by firing .05%S oil, for only limited time periods. Fossil fuel fired combustion turbine Unit 1 began commercial operation in 1994.}

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:

Unit No.	MMBtu/hr Heat Input	Fuel Type
001	367*	Natural Gas
	372*	Fuel Oil

* Based on 101.3 kilopascals pressure, 288 Kelvin and 60% relative humidity (ISO standard day conditions), and lower heating value of the fuel fired.

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each emission unit for the purposes of confirming that emissions testing is conducted within 95 to 100 percent of the emission unit's rated capacity (or to limit future operation to 105 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability}
[Rules 62-4.160(2) and 62-210.200(PTE),F.A.C.; and, AC 49-205703 (PSD-FL-182)]

A.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **C.8**.
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation - Fuels. The only fuel(s) allowed to be burned are natural gas and number 2 fuel oil (0.05%), except that firing of number 2 fuel oil is limited to no more than 1000 hours per year if natural gas is unavailable, or no more than 800 hours per year if gas is available. The sulfur content of the fuel oil shall not exceed 0.05%, by weight.
{Note: The limitations of specific conditions A.3 and A.6 are more stringent than the NSPS sulfur dioxide limitation and thus assure compliance with 40 CFR 60.333 and 60.334}
[Rule 62-213.410, F.A.C., AC 49-205703 (PSD-FL-182)]

Emission Limitations and Standards

A.4. Visible Emissions. Visible emissions shall not exceed 10 percent opacity, except for during startup, shutdown or periods of part load operation, at which time visible emissions shall not exceed 20 percent opacity.
[AC 49-205703 (PSD-FL-182)]

A.5. The maximum allowable emissions from Unit 1 shall not exceed the emission limitations listed below.

Pollutant	Emission Limits			Basis
	Gas	Number 2 Fuel Oil	Equivalent Emissions Tons/Year [a, b]	
NO_x [c]	25/15 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	116.9	BACT
SO_2	nil	20 lb/hr	10.0	BACT
PM	0.0245lb/mmBtu	0.0323 lb/MMBtu	40.9	BACT
H_2SO_4	nil	2.2 lb/hr	1.1	BACT
VOC	1.4 lb/hr	3 lb/hr	6.9	BACT
CO	30 ppmvd	63 ppmvd	193.2	BACT
Opacity	10% (see A.4.)	10% (see A.4.)		BACT
Be [d]	nil	2.5e-6 lb/MMBtu	< 1	BACT
As [d]	nil	4.2e-6 lb/MMBtu	< 1	AC 49-205703
Hg [d]	nil	3.1e-6 lb/MMBtu	< 1	AC 49-205703
Pb [d]	nil	2.8e-5 lb/MMBtu	< 1	AC 49-205703

a. Tons per year based on 7760 hrs/yr for natural gas firing, 1000 hrs/yr for number 2 fuel oil firing.
b. Based on 372 MMBtu/hr for number 2 fuel oil and 367 MMBtu/hr for natural gas.
c. NO_x emission limits were permitted to be 25 ppmvd while firing natural gas until 1/1/98 via original application. An amendment to permit (AC0970043-003) was made on 5/19/97 extending the date for the reduced NO_x emission limit of 15 ppmvd until 1/1/99. An

additional extension was granted on December 15, 1998 via amendment AC0970043-005 further extending this date until 1/1/00.

d. Limits based upon an approved emission factor, which is subject to change in the future.

Test Methods and Procedures

A.6. Annual Compliance Tests. Emission testing for visible emissions and NO_x shall be performed annually, in accordance with specific condition **A.8.**, with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NO_x.

If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
[Rules 62-297.401 and 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

A.7. Testing for PM, CO, VOC. Particulate matter tests shall be conducted using EPA test methods 5 or 17. Alternatively, the opacity emissions test may be used unless the 10% opacity limit is exceeded. Carbon monoxide tests shall be conducted using EPA test method 10. VOC tests shall be conducted using EPA test method 25A.
[Rule 62-297.401, F.A.C., and AC 49-205703 (PSD-FL-182)]

A.8. Additional Test Requirements. Test results shall be the average of three valid runs. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity, which is defined as 95-100 percent of the maximum heat input rate allowed by this permit, achievable for the average ambient air temperature during the test. If it is impracticable to test at permitted capacity, the emissions unit may be tested at less than permitted capacity. In such cases, subsequent operation is limited by adjusting downward the entire heat input vs. inlet temperature curve by the increment equal to the difference between the maximum permitted heat input value and 105 percent of the value reached during the test. 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. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report.
[AC 49-205703 (PSD-FL-182)]

A.9. Sulfur Dioxide - Sulfur Content. **The permittee elected to use fuel sampling and analysis in lieu of installing a continuous monitoring system for SO_2 as required by the NSPS.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. The permittee shall demonstrate compliance with the SO_2 limit by EPA test method 8 or fuel sampling and analysis. The permittee shall demonstrate compliance with the gaseous fuel sulfur limit via record keeping. Excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05% sulfur, by weight.
[AC 49-205703 (PSD-FL-182)]

A.10. Fuel Sampling & Analysis - Sulfur/Nitrogen and Lower Heating Value. The following fuel sampling and analysis program shall be used to demonstrate compliance with the sulfur dioxide standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest editions, to analyze a representative sample of the blended fuel following each fuel delivery. ASTM D3246-81, or its latest edition, shall be used for sulfur content of gaseous fuel.

b. Record daily the amount of each fuel fired, density of each fuel, heating value, nitrogen content and the percent sulfur content by weight of fuel oil as specified in 40 CFR 60.334. [Rule 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

Monitoring of Operations

A.11 Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides in accordance with the requirements of 40 CFR 75. While water injection is being utilized for NO_x control, water to fuel ratio and fuel bound nitrogen is not required to be continuously monitored as long as the permittee will report excess emissions using the data collected by the continuous monitoring system in accordance with the following conditions:

1. Each NO_x CEMS must be capable of calculating NO_x emissions concentrations corrected to 15% O2 and ISO conditions.
2. Monitor data availability shall be no less than 95 percent on a quarterly basis.
3. NO_x CEMS should provide at least 4 data points for each hour and calculate a one-hour average.

To implement condition 1, KUA shall use ambient data (temperature, relative humidity, pressure) to correct excess emissions data to ISO conditions if requested by the Department. If monitor availability drops below 95% on a quarterly basis as prescribed in condition 2, KUA shall use water to fuel ratio and fuel-bound nitrogen data to monitor excess emissions in subsequent quarters until the minimum CEMS monitor availability is above 95%. The use of CEMS to monitor excess emissions is more stringent than the surrogate parameter monitoring in 40 CFR 60.334 since the CEMS directly measures NO_x emissions. The CEMS also provides monitoring when no water injection is used to control NOx emissions (i.e., when firing natural gas, dry low NO_x burners are used).
[AC 49-205703 (PSD-FL-182)]

A.12 Excess Emissions by CEMS. The CEMS shall be used to determine periods of excess emissions as per 40 CFR 60.334. Excess emissions are defined for this emissions unit as any 60-minute period during which the average emissions exceed the emission limits of specific condition **A.5.** of this permit. Periods of startup, shutdown and malfunction shall be monitored, recorded and reported with excess emissions following the format and requirements of 40 CFR 60.7.
[AC 49-205703 (PSD-FL-182)]

Record Keeping and Reporting Requirements

A.13. Excess Emission Reports. Semi-annual excess emission reports shall be submitted to the DEP's Central District Office. These reports shall be postmarked by the 30th day following the end of each calendar half. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.
[AC 49-205703 (PSD-FL-182)]

A.14. Natural Gas Sulfur Content Records Required. The owner or operator shall receive and maintain records of sulfur content of natural gas provided by the natural gas supplier, as per 40 CFR 60.334. The records shall report total sulfur content in terms of grains of sulfur per hundred cubic feet (standard conditions).
[AC 49-205703 (PSD-FL-182)]

A.15. Additional Reports Required. The owner or operator shall report the following with the Annual Operating Report (AOR) by March 1 of each calendar year: sulfur and nitrogen contents, by weight, and lower heating value of the fuel oil being fired, annual fuel consumption of number 2 fuel oil and natural gas, hours of operation per fuel usage and air emission limits.
[Rule 62-210.370(3), F.A.C., and AC 49-205703 (PSD-FL-182)]

Other Conditions

A.16. Maintain Capability to install an SCR. This emissions unit is permitted for maximum NO_x emission levels of 15 (gas)/42 (oil) ppmv. The Department will revise permitted emission levels for NO_x if the manufacturer achieves an even lower NO_x emission, pursuant to F.A.C. Rule 62-4.080. The permittee shall maintain capability for future installation of a selective catalytic reduction (SCR) system. This is required in the event that the permittee is unable to comply with the permitted NO_x levels and the Department requires an SCR to be installed. In the event an SCR system is required to be installed, the emission limitations shall be established at the time of installation by stack test results and through a revised determination of BACT.
[AC 49-205703 (PSD-FL-182)]

A.17. This emissions unit is also subject to conditions **C.1.** through **C.13.** contained in **Subsection C. Common Conditions.**

A.18. This emissions unit is also subject to conditions **D.1.** through **D.6.** contained in **Subsection D. NSPS Common Conditions.**

Subsection B. This section addresses the following emissions unit.

002	Combined Cycle Combustion Turbine Unit 2, rated at 120 MW, 869 MMBtu/hr for natural gas and 928 MMBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack.

{Permitting notes: This emissions unit is regulated under Acid Rain, Phase II; Rule 62-210.300, F.A.C., Permits Required; and, is subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. The affected facility to which this subpart applies is the combined cycle gas turbine, Unit 2. This unit underwent a BACT Determination dated April 7, 1993. BACT Limits were incorporated into the subsequent air construction/PSD permits including AC 49-205703 (PSD-FL-182). Exhaust is vented through the heat recovery steam generator that is not equipped with duct burners and then through a 75 ft. stack. NO_x emissions are controlled by low-NO_x combustors, and by water injection, whereas SO_2 and H_2SO_4 emissions are controlled by firing 0.05%S oil for only limited time periods. The turbine exhaust may also be vented through a bypass stack for simple cycle operation when the HRSG or steam turbine is down for maintenance and/or repair. The turbine began commercial operation in 1995.}

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

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

B.1. <u>Permitted Capacity</u>. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
002	869*	Natural Gas
	928*	No. 2 Fuel Oil

* Based on 101.3 kilopascals pressure, 288 Kelvin and 60% relative humidity (ISO standard day conditions), and lower heating value of the fuel fired.

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 95 to 100 percent of the emission unit's rated capacity (or to limit future operation to 105 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability}
[Rules 62-4.160(2), 62-210.200(PTE),F.A.C. and AC 49-205703 (PSD-FL-182)]

B.2. <u>Emissions Unit Operating Rate Limitation After Testing</u>. See specific condition **C.8.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation - Fuels. The only fuel(s) allowed to be burned are natural gas and number 2 fuel oil (0.05%), except that firing of number 2 fuel oil is limited to no more than 1000 hours per year if natural gas is unavailable, or no more than 800 hours per year if gas is available. The sulfur content of the fuel oil shall not exceed 0.05%, by weight.
{Note: The limitations of specific conditions A.3 and A.6 are more stringent than the NSPS sulfur dioxide limitation and thus assure compliance with 40 CFR 60.333 and 60.334}
[Rule 62-213.410, F.A.C., AC 49-205703 (PSD-FL-182)]

Emission Limitations and Standards

B.4. Visible Emissions. Visible emissions shall not exceed 10 percent opacity, except for during startup, shutdown or periods of part load operation, at which time visible emissions shall not exceed 20 percent opacity.
[AC 49-205703 (PSD-FL-182)]

B.5. The maximum allowable emissions from Unit 2 shall not exceed the emission limitations listed below.

Pollutant	**Emission Limits**			**Basis**
	Gas	**Number 2 Fuel Oil**	**Equivalent Emissions Tons/Year** [a, b]	
NO_x [c]	15 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	290.6	BACT
SO_2	nil	52 lb/hr	26	BACT
PM	0.010 lb/MMBtu	0.0162 lb/MMBtu	41.2	BACT
H_2SO_4	nil	5.72 lb/hr	2.86	BACT
VOC	2 lb/hr	5 lb/hr	10.26	BACT
CO	20 ppmvd	20 ppmvd	242	BACT
Opacity	10% (see B.4.)	10% (see B.4.)		BACT
Be [d]	nil	2.5e-6 lb/MMBtu	< 1	BACT
As [d]	nil	4.2e-6 lb/MMBtu	< 1	AC 49-205703
Hg [d]	nil	3.0e-6 lb/MMBtu	< 1	AC 49-205703
Pb [d]	nil	2.8e-5 lb/MMBtu	< 1	AC 49-205703

a. Tons per year based on 7760 hrs/yr for natural gas firing, 1000 hrs/yr for number 2 fuel oil firing.
b. Based on 928 MMBtu/hr for number 2 fuel oil and 869 MMBtu/hr for natural gas.
c. NO_x emission limits were permitted to be 25 ppmvd while firing natural gas until 1/1/98 via original application.
d. Limits based upon an approved emission factor, which is subject to change in the future.

B.6. Annual Compliance Tests. Emission testing for visible emissions and NO_x shall be performed annually, in accordance with specific condition **B.8.**, with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NO_x.

If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
[Rules 62-297.401 and 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

B.7. Testing for PM, CO, VOC. Particulate matter tests shall be conducted using EPA test methods 5 or 17. Alternatively, the opacity emissions test may be used unless the 10% opacity limit is exceeded. Carbon monoxide tests shall be conducted using EPA test method 10. VOC tests shall be conducted using EPA test method 25A.
[Rule 62-297.401, F.A.C., and AC 49-205703 (PSD-FL-182)]

B.8. Additional Test Requirements. Test results shall be the average of three valid runs. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity, which is defined as 95-100 percent of the maximum heat input rate allowed by this permit, achievable for the average ambient air temperature during the test.. If it is impracticable to test at permitted capacity, the emissions unit may be tested at less than permitted capacity. In such cases, subsequent operation is limited by adjusting downward the entire heat input vs. inlet temperature curve by the increment equal to the difference between the maximum permitted heat input value and 105 percent of the value reached during the test. 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. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Dept. with the compliance test report.
[AC 49-205703 (PSD-FL-182)]

B.9. Sulfur Dioxide - Sulfur Content. **The permittee elected to use fuel sampling and analysis in lieu of installing a continuous monitoring system for SO_2 as required by the NSPS.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. The permittee shall demonstrate compliance with the SO_2 limit by EPA test method 8 or fuel sampling and analysis. The permittee shall demonstrate compliance with the gaseous fuel sulfur limit via record keeping. Excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05% sulfur by weight.
[AC 49-205703 (PSD-FL-182)]

B.10. Fuel Sampling & Analysis - Sulfur/Nitrogen and Lower Heating Value. The following fuel sampling and analysis program shall be used to demonstrate compliance with the sulfur dioxide standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest editions, to analyze a representative sample of the blended fuel following each fuel delivery. ASTM D3246-81, or its latest edition, shall be used for sulfur content of gaseous fuel.

b. Record daily the amount of each fuel fired, density of each fuel, heating value, nitrogen content and the percent sulfur content by weight of fuel oil as specified in 40 CFR 60.334.

[Rule 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

Monitoring of Operations

B.11 Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides in accordance with the requirements of 40 CFR 75. While water injection is being utilized for NO_x control, water to fuel ratio and fuel bound nitrogen is not required to be continuously monitored as long as the permittee will report excess emissions using the data collected by the continuous monitoring system in accordance with the following conditions:

1. Each NO_x CEMS must be capable of calculating NO_x emissions concentrations corrected to 15% O2 and ISO conditions.
2. Monitor data availability shall be no less than 95 percent on a quarterly basis.
3. NO_x CEMS should provide at least 4 data points for each hour and calculate a one-hour average.

To implement condition 1, KUA shall use ambient data (temperature, relative humidity, pressure) to correct excess emissions data to ISO conditions if requested by the Department. If monitor availability drops below 95% on a quarterly basis as prescribed in condition 2, KUA shall use water to fuel ratio and fuel-bound nitrogen data to monitor excess emissions in subsequent quarters until the minimum CEMS monitor availability is above 95%. The use of CEMS to monitor excess emissions is more stringent than the surrogate parameter monitoring in 40 CFR 60.334 since the CEMS directly measures NO_x emissions. The CEMS also provides monitoring when no water injection is used to control NOx emissions (i.e., when firing natural gas, dry low NO_x burners are used).

[AC 49-205703 (PSD-FL-182)]

B.12. Excess Emissions by CEMS. The CEMS shall be used to determine periods of excess emissions as per 40 CFR 60.334. Excess emissions are defined for this emissions unit as any 60-minute period during which the average emissions exceed the emission limits of specific condition **B.5.** of this permit. Periods of startup, shutdown and malfunction shall be monitored, recorded and reported with excess emissions following the format and requirements of 40 CFR 60.7.

[AC 49-205703 (PSD-FL-182)]

Record Keeping and Reporting Requirements

B.13. Excess Emission Reports. Quarterly excess emission reports shall be submitted to the DEP's Central District Office. These reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.
[AC 49-205703 (PSD-FL-182)]

B.14. Natural Gas Sulfur Content Records Required. The owner or operator shall receive and maintain records of sulfur content of natural gas provided by the natural gas supplier, as per 40 CFR 60.334. The records shall report total sulfur content in terms of grains of sulfur per hundred cubic feet (standard conditions).
[AC 49-205703 (PSD-FL-182)]

B.15. Additional Reports Required. The owner or operator shall report the following with the Annual Operating Report (AOR) by March 1 of each calendar year: sulfur and nitrogen contents, by weight, and lower heating value of the fuel oil being fired, annual fuel consumption of number 2 fuel oil and natural gas, hours of operation per fuel usage and air emission limits.
[Rule 62-210.370(3), F.A.C., and AC 49-205703 (PSD-FL-182)]

Other Conditions

B.16. Maintain Capability to install an SCR. This emissions unit is permitted for maximum NO_x emission levels of 15 (gas)/42 (oil) ppmv. The Department will revise permitted emission levels for NO_x if the manufacturer achieves an even lower NO_x emission, pursuant to F.A.C. Rule 62-4.080. The permittee shall maintain capability for future installation of a selective catalytic reduction (SCR) system. This is required in the event that the permittee is unable to comply with the permitted NO_x levels and the Department requires an SCR to be installed. In the event an SCR system is required to be installed, the emission limitations shall be established at the time of installation by stack test results and through a revised determination of BACT.
[AC 49-205703 (PSD-FL-182)]

B.17. This emissions unit is also subject to conditions **C.1.** through **C.13.** contained in **Subsection C. Common Conditions.**

B.18. This emissions unit is also subject to conditions **D.1.** through **D.6.** contained in **Subsection D. NSPS Common Conditions.**

Subsection C. Common Conditions.

E.U. ID No.	Brief Description
001	Simple Cycle Combustion Turbine Unit 1, rated at 40 MW, 367 MMBtu/hr for natural gas and 372 MMBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack .
002	Combined Cycle Combustion Turbine Unit 2, rated at 120 MW, 869 MMBtu/hr for natural gas and 928 MMBtu/hr for number 2 fuel oil, capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack .

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

Essential Potential to Emit (PTE) Parameters

C.1. Hours of Operation. The emissions units may operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.]

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.}

Excess Emissions

{Pemitting note: The excess emissions rule at 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

C.2. 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.]

C.3. 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.]

Monitoring of Operations

C.4. 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.]

C.5. Visible Emissions. The test method for visible emissions for emissions units 001 (Unit 1) and 002 (Unit 2) shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800 and 62-297.401, F.A.C.]

C.6. 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.]

C.7. 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.]

C.8. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 95 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 105 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.
[Rule 62-297.310(2), F.A.C.]

C.9. 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.
(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.]

C.10. 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.]

Record Keeping and Reporting Requirements

C.11. Excess Emissions - Notification. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Central District Air Section 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 Central District Air Section.
[Rule 62-210.700(6), F.A.C.]

C.12. Excess Emissions - Report. Submit to the Central District Air Section a written report of emissions in excess of emission limiting standards as set forth in this permit, for each calendar

quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations.
[Rule 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

C.13. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Central District Air Section on the results of each such test.
(b) The required test report shall be filed with the Central District Air Section 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 Central District Air Section 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.]

Subsection D. NSPS Common Conditions.

E.U. ID No.	Brief Description
001	Simple Cycle Combustion Turbine Unit 1, rated at 40 MW, 367 MMBtu/hr for natural gas and 372 MMBtu/hr for number 2 fuel oil, capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack .
002	Combined Cycle Combustion Turbine Unit 2, rated at 120 MW, 869 MMBtu/hr for natural gas and 928 MMBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack .

{Permitting Note: The emissions units above are subject to the following conditions from 40 CFR 60 Subpart A, General Provisions. The affected facilities to which this subpart applies are simple cycle combustion turbine, Unit 1 and the combined cycle combustion turbine, Unit 2.}

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

D.1. Pursuant to 40 CFR 60.7 Notification And Record Keeping.

(a) Any owner or operator subject to the provisions of this part 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.

(b) The owner or operator subject to the provisions of this part 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.

(c) The 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.
(d) The summary report form shall contain the information and be in the format shown in Figure 1 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]

(f) The owner or operator subject to the provisions of this part 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 this part recorded in a permanent form suitable for inspection. The file shall be retained for at least <u>five</u> years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7 and Rule 62-213.440(1)(b)2.b., F.A.C.]

D.2. <u>Pursuant to 40 CFR 60.8 Performance Tests</u>.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart.
(c) 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.
(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining

compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.
[40 CFR 60.8]

D.3. Pursuant to 40 CFR 60.11 Compliance With Standards And Maintenance Requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).
(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
(d) 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.
(e)(5) 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 Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he 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 Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance.
[40 CFR 60.11]

D.4. Pursuant to 40 CFR 60.12 Circumvention.

No owner or operator subject to the provisions of this part 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]

D.5. Pursuant to 40 CFR 60.13 Monitoring Requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section 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 to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.
(c) 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/she 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 40 CFR 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 40 CFR 60.8 is conducted.
(2) Except as provided in 40 CFR 60.13(c)(1), the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.
(d)(1) Owners and operators of all continuous emission monitoring systems 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.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems 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.

(f) All continuous monitoring systems 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.

(g) 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 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.

(h) 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 recorder during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

[40 CFR 60.13]

D.6. Pursuant to 40 CFR 60.17 Incorporations by Reference.

The materials listed below are incorporated by reference in the corresponding sections noted. [Note: The remainder of this section has not been reproduced in this permit for brevity. See 40 CFR 60.17 for materials incorporated by reference.]
[40 CFR 60.17]

Section IV. This section is the Acid Rain Part.

Operated by: Kissimmee Utility Authority
ORIS code: 7238

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

The emissions unit(s) listed below are regulated under Acid Rain, Phase II.

E.U. ID No.	Brief Description
001	Simple Cycle Combustion Turbine, Unit 1
002	Combined Cycle Combustion Turbine, Unit 2

A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, is 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 12/27/95.
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO_2) allowance allocations for each Acid Rain unit is as follows:

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003
001	1	**SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73**	0*	0*	0*	0*
002	2	**SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73**	0*	0*	0*	0*

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

A.3. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.4. Comments, notes, and justifications.
None.

Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers (version dated 02/05/97)

Abbreviations and Acronyms:

°F: Degrees Fahrenheit
BACT: Best Available Control Technology
CFR: Code of Federal Regulations
DEP: State of Florida, Department of Environmental Protection
DARM: Division of Air Resource Management
EPA: United States Environmental Protection Agency
F.A.C.: Florida Administrative Code
F.S.: Florida Statute
ISO: International Standards Organization
LAT: Latitude
LONG: Longitude
MMBtu: million British thermal units
MW: Megawatt
ORIS: Office of Regulatory Information Systems
SOA: Specific Operating Agreement
UTM: Universal Transverse Mercator

Citations:

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, guidance memorandums, permit numbers, and ID numbers.

Code of Federal Regulations:

Example: **[40 CFR 60.334]**

Where:	40	reference to	Title 40
	CFR	reference to	Code of Federal Regulations
	60	reference to	Part 60
	60.334	reference to	Regulation 60.334

Florida Administrative Code (F.A.C.) Rules:

Example: **[Rule 62-213, F.A.C.]**

Where:	62	reference to	Title 62
	62-213	reference to	Chapter 62-213
	62-213.205	reference to	Rule 62-213.205, F.A.C.

ISO: International Standards Organization refers to those conditions at 288 degrees K, 60 percent relative humidity, and 101.3 kilopascals pressure.

Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers (continued)

Identification Numbers:

Facility Identification (ID) Number:

Example: Facility ID No.: 1050221

Where:

105 = 3-digit number code identifying the facility is located in Polk County
0221 = 4-digit number assigned by state database.

Permit Numbers:

Example: 1050221-002-AV, or
1050221-001-AC

Where:

AC = Air Construction Permit
AV = Air Operation Permit (Title V Source)
105 = 3-digit number code identifying the facility is located in Polk County
0221 = 4-digit number assigned by permit tracking database
001 or 002 = 3-digit sequential project number assigned by permit tracking database

Example: PSD-FL-185
PA95-01,
AC53-208321

Where:

PSD= Prevention of Significant Deterioration Permit
PA = Power Plant Siting Act Permit
AC = old Air Construction Permit numbering

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

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rule 62.210.300(3)(a), F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

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

Brief Description of Emissions Units and/or Activities

1. Cooling tower.

Appendix H-1, Permit History/ID Number Changes

Permit History (for tracking purposes):

E.U. ID No.	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1,2]	Revised Date(s)
Unit 1	Simple Cycle Comb. Turbine, Unit 1	AC49-205703 PSD-FL-182	4/9/93	11/1/96	9/16/94, 5/8/95	
		AC0970043-004				5/19/97
		AC0970043-003				8/15/97
Unit 2	Combined Cycle Gas Turbine, Unit 2	AC49-205703 PSD-FL-182	4/9/93	11/1/96	9/16/94, 5/8/95	
		AC0970043-004				5/19/97
		AC0970043-003				8/15/97

ID Number Changes (for tracking purposes):

From: **Facility ID No.:** 30ORL490043

To: **Facility ID No.:** 0970043

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}

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

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.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'exempt emissions units'.

E.U. ID No.	Brief Description of Emissions Units and/or Activity
	Fuel oil, gasoline and lube oil storage tanks. Tanks are:
003	Tank 1 (300,000 gal. capacity) distillate fuel oil;
004	Tank 2 (700,000 gal. capacity) distillate fuel oil;

Appendix S
Permit Summary Tables

Table 1-1, Summary of Air Pollutant Emission Standards

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

Emiss Unit	Brief Description
001	Simple Cycle Gas Turbine, Unit 1, rated at 40 MW.

			Allowable Emissions[a]			Equivalent			
Pollutant	Fuel(s)	Hours	Standard(s)	lb/hr	TPY	lb/hr	TPY	Regulatory	See Permit
VE	No 2 Oil Nat Gas	8760	10 % opacity					AC 49-205703	A.4.
SO_2	No 2 Oil Nat Gas	1000	0.05% S by weight, fuel oil	20			10	AC 49-205703	A.9., A.10., A.13.
NO_x	No. 2 Fuel Oil	1000	42 ppmvd at 15% oxygen on a dry	63			31.5	AC 49-205703	A.15.
NO_x	Natural Gas	8760	25/15 ppmvd at 15% oxygen dry	22			85.4	AC 49-205703	A.15.
PM	No. 2 Fuel Oil	1000	0.0323 lb/MMBtu			12.0	6.0	AC 49-205703	A.5., A.7.
PM	Natural Gas	8760	0.0245 lb/MMBtu			9	34.9	AC 49-205703	A.5., A.7.
VOC	No. 2 Fuel Oil	1000	3 lb/hour	3			1.5	AC 49-205703	A.5., A.7.
VOC	Natural Gas	8760	1.4 lb/hour	1.4			5.4	AC 49-205703	A.5., A.7.
CO	No. 2 Fuel Oil	1000	63 ppmvd at 15% oxygen on a dry	76			38	AC 49-205703	A.5., A.7.
CO	Natural Gas	8760	30 ppmvd at 15% oxygen on a dry	40			155.2	AC 49-205703	A.5., A.7.
Hg	No. 2 Fuel Oil	1000	3.1e-6 lb/MMBtu			<1	<1	AC 49-205703	A.5.
As	No. 2 Fuel Oil	1000	4.2e-6 lb/MMBtu			<1	<1	AC 49-205703	A.5.
Be	No. 2 Fuel Oil	1000	2.5e-6 lb/MMBtu			<1	<1	AC 49-205703	A.5.
Pb	No. 2 Fuel Oil	1000	2.8e-5 lb/MMBtu			<1	<1	AC 49-205703	A.5.

Notes for EU 001:

a lb/hour and TPY values based on using number 2 fuel oil for 1000 hours per year; for natural gas using 7760 hours per year.
[1] The "Equivalent Emissions" listed are for informational purposes only. They are based upon 7760 hours per year of gas operation and 1000 hours per year of #2 oil operation. [Rule 62-213.205, F.A.C.]
* Firing of number 2 fuel oil is limited to no more than 1000 hours per year to the unit for any reason.

Appendix S
Permit Summary Tables

Emiss Unit	Brief Description
002	Combined Cycle Gas Turbine, Unit 2, rated at 120 MW.

			Allowable Emissions[a]			Equivalent			
Pollutant	Fuel(s)	Hours	Standard(s)	lb/hr	TPY	lb/hr	TPY	Regulatory	See Permit
VE	No 2 Oil Nat Gas	8760	10 % opacity					AC 49-205703	A.4.
SO_2	No 2 Oil Nat Gas	1000	0.05% S by weight, fuel oil	52			26	AC 49-205703	A.9., A.10., A.13.
NO_x	No. 2 Fuel Oil	1000	42 ppmvd at 15% oxygen on a dry	170			85.0	AC 49-205703	A.15.
NO_x	Natural Gas	8760	15 ppmvd at 15% oxygen on a dry	53			205.6	AC 49-205703	A.15.
PM	No. 2 Fuel Oil	1000	0.0162 lb/MMBtu			15.0	7.5	AC 49-205703	A.5., A.7.
PM	Natural Gas	8760	0.0100 lb/MMBtu			8.7	33.7	AC 49-205703	A.5., A.7.
VOC	No. 2 Fuel Oil	1000	5.0 lb/hour	5			2.5	AC 49-205703	A.5., A.7.
VOC	Natural Gas	8760	2.0 lb/hour	2			7.76	AC 49-205703	A.5., A.7.
CO	No. 2 Fuel Oil	1000	20 ppmvd at 15% oxygen on a dry	65			32.5	AC 49-205703	A.5., A.7.
CO	Natural Gas	8760	20 ppmvd at 15% oxygen on a dry	54			209.5	AC 49-205703	A.5., A.7.
Hg	No. 2 Fuel Oil	1000	3.0e-6 lb/MMBtu			<1	<1	AC 49-205703	A.5.
As	No. 2 Fuel Oil	1000	4.2e-6 lb/MMBtu			<1	<1	AC 49-205703	A.5.
Be	No. 2 Fuel Oil	1000	2.5e-6 lb/MMBtu			<1	<1	AC 49-205703	A.5.
Pb	No. 2 Fuel Oil	1000	2.8e-5 lb/MMBtu			<1	<1	AC 49-205703	A.5.

Notes for EU 002:

a lb/hour and TPY values based on using number 2 fuel oil for 1000 hours per year; for natural gas using 7760 hours per year.
[1] The "Equivalent Emissions" listed are for informational purposes only. They are based upon 7760 hours per year of gas operation and 1000 hours per year of #2 oil operation. [Rule 62-213.205, F.A.C.]
* Firing of number 2 fuel oil is limited to no more than 1000 hours per year to the unit for any reason.

Appendix S
Permit Summary Tables

Table 2-1, Summary of Compliance Requirements

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

Emissions Unit	Brief Description
001	Simple Cycle Combustion Turbine, Unit 1, rated at 40 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	No 2 Fuel Oil, Nat. Gas	EPA Method 9	Annual	August 1st	1 hour	No	A.6.
SO_2	"	Method 8 for Fuel oil firing only; Fuel Sampling & Analysis	As Fired			Yes*	A.9, A.10.
NO_x	"	EPA Test Method 20	Annual	August 1st	3 hours	Yes	A.6.
PM	"	EPA Test Methods 5 or 17	Only if 10% Opacity is exceeded		3 hours	No	A.7.
VOC	"	EPA Test Method 25A	Initial Compliance			No	A.7.
CO	"	EPA Test Method 10	Annual			No	A.7.
Hg	No.2 oil	EPA Method 101 or fuel sampling	Initial Compliance			No	A.5.
As	No.2 oil	Fuel sampling	Initial Compliance			No	A.5.
Be	No.2 oil	EPA Method 104 or fuel sampling	Initial Compliance			No	A.5.
Pb	No.2 oil	Fuel sampling	Initial Compliance			No	A.5.

Notes for EU 001:

* Continuous monitoring of fuel consumption required.
[1] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
[2] CMS = continuous monitoring system
See also Section C for general testing requirements

Appendix S
Permit Summary Tables

Emissions Unit	Brief Description
002	Combined Cycle Combustion Turbine, Unit 2, rated at 120 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	No 2 Fuel Oil, Nat. Gas	EPA Method 9	Annual	August 1st	1 hour	No	B.6.
SO_2	"	Method 8 for Fuel oil firing only; Fuel Sampling & Analysis	As Fired			Yes*	B.9, B.10.
NO_x	"	EPA Test Method 20	Annual	August 1st	3 hours	Yes	B.6.
PM	"	EPA Test Methods 5 or 17	Only if 10% Opacity is exceeded		3 hours	No	B.7.
VOC	"	EPA Test Method 25A	Initial Compliance			No	B.7.
CO	"	EPA Test Method 10	Annual			No	B.7.
Hg	No.2 oil	EPA Method 101 or fuel sampling	Initial Compliance			No	B.5.
As	No.2 oil	Fuel sampling	Initial Compliance			No	B.5.
Be	No.2 oil	EPA Method 104 or fuel sampling	Initial Compliance			No	B.5.
Pb	No.2 oil	Fuel sampling	Initial Compliance			No	B.5.

Notes for EU 002:

* Continuous monitoring of fuel consumption required.

Notes:

[1] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
[2] CMS = continuous monitoring system
See also Section F for general testing requirements.

Appendix TV-1, the Title V Core Conditions, has been provided only to the applicant. The most recent version of these conditions may be obtained from the Department's Internet Web site at:

http://www2.dep.state.fl.us/air/

If you do not have access to the Internet and would like a copy of Appendix TV, please contact Michael P. Halpin, Department of Environmental Protection, Division of Air Resources Management, Bureau of Air Regulation, Mail Station 5505, 2600 Blair Stone Road, Tallahassee, FL 32399-2400, 850/921-9530

Best Available Control Technology (BACT) Determination
Kissimmee Utility Authority
Osceola County
PSD-FL-182

The applicant proposes to install two combustion turbine generators at their facility near Intercession City, Osceola County. These generator systems will consist of: 1) one nominal 80 megawatt (MW) General Electric PG7111EA combined cycle combustion turbine (CCCT), with exhaust through a heat recovery steam generator (HRSG), which will be used to power a nominal 40 MW steam turbine and 2) a 40 MW General Electric LM6000 simple cycle combustion turbine (SCCT).

The PG7111EA combustion turbine will be capable of operating on a combined and a simple cycle mode. The LM6000 will operate on a simple cycle mode. The applicant has requested to burn natural gas or fuel oil No. 2, with a 0.05 percent sulfur content, on a continuous basis (8,760 hrs/year). The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity factor, ISO conditions, and type of fuel fired to be as follows:

Pollutant	Emissions (TPY) Oil		Gas		PSD Significant Emission Rate (TPY)
	PG7111EA	LM6000	PG7111EA	LM6000	
NO_x	744.6	275.9	429.2	157.7	40
SO_2	227.8	87.6	nil	nil	40
PM/PM_{10}	65.7	52.6	30.7	39.4	25/15
CO	284.7	332.9	236.5	175.2	100
VOC	21.9	13.1	8.8	6.1	40
H_2SO_4	25.1	9.6	nil	nil	7
Be	0.0099	0.0035	---	---	0.0004
Hg	0.012	0.005	---	---	0.1
Pb	0.044	0.141	---	---	0.6

Florida Administrative Code (F.A.C.) Rule 17-2.500(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

June 2, 1992

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	25 ppmvd @ 15% O_2 (natural gas burning) 42 ppmvd @ 15% O_2 (for oil firing) PG7111(EA) Control Technology: Low NO_x Burners GE LM6000 Control Technology: Water Injection

SO_2	0.3% sulfur by weight (but limited to 0.05% sulfur for modeling purposes)
CO, VOC	Combustion Control
PM/PM_{10}	Combustion Control

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-296, Air Pollution, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, than the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from combined cycle power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- Combustion Products (e.g., particulates). Controlled generally by good combustion of clean fuels.

- Products of Incomplete Combustion (e.g., CO). Control is largely achieved by proper combustion techniques.

- Acid Gases (e.g., NO_X). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT POLLUTANT ANALYSIS

COMBUSTION PRODUCTS

Particulate Matter (PM/PM_{10})

The design of this system ensures that particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbines when burning natural gas and fuel oil will not exceed 15 lbs/hr (oil) and 7 lbs/hr (gas) for the PG7111 and 12 lbs/hr (oil) and 9 lbs/hr (gas) for the LM6000. The Department accepts the applicant's proposed control for particulate matter and heavy metals.

Lead, Mercury, Beryllium (Pb, Hg, Be)

The Department agrees with the applicant's rationale that there are no feasible methods to control lead, mercury, and beryllium; except by limiting the inherent quality of the fuel.

Although the emissions of these toxic pollutants could be controlled by particulate control devices, such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of these pollutants.

PRODUCTS OF INCOMPLETE COMBUSTION

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The emissions of carbon monoxide exceed the PSD significant emission rate of 100 TPY. The applicant has indicated that the carbon monoxide emissions from the proposed combined cycle turbine with a "quiet combustor" are 10 ppmv for natural gas firing and 20 ppmv for fuel oil firing. However, for a dry low NO_X combustor, the emission limit is 20 ppmvd for both oil and gas. For the simple cycle CT, the CO emissions for firing natural gas and fuel oil are 30 ppmv and 63 ppmv, respectively.

The majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds minimization, however, additional control is achievable through the use of catalytic oxidation. Catalytic oxidation is a postcombustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10-ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be technically feasible for gas turbines fired with fuel oil. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for a natural gas-fired unit; however, the cost effectiveness of $4,437 per ton for the LM6000 and $10,560 per ton for the PG7110EA of CO/VOC removed will have an economic impact on this project.

The Department is in agreement with the applicant's proposal of combustor design and good operating practices as BACT for CO and VOCs for this cogeneration project.

ACID GASES

Nitrogen Oxides (NO_x)

The emissions of nitrogen oxides represent a significant proportion of the total emissions generated by this project, and need to be controlled if deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant has stated that BACT for nitrogen oxides will be met by using water injection and advanced combustor design to limit emissions to 25 ppmvd (corrected to 15% O_2) when burning natural gas and 42 ppmvd (corrected to 15% O_2) when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction will decrease to approximately 86 percent.

The effect of exhaust gas temperature on NO_x reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NO_x control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

As stated by the applicant, the exhaust temperatures of the proposed simple cycle CTs for this site are between 600°F to 800°F.

At temperatures of 1,000°F and above, the zeolite catalyst (reported to operate within 600°F to 950°F) will be irreparably damaged. In this case, application of an SCR system using a zeolite catalyst on a simple-cycle operation appears to be technically feasible.

However, the applicant has rejected using SCR on the simple cycle CT because of economic and environmental impacts.

Although technically feasible, the applicant has also rejected using SCR on the combined cycle because of economic, energy, and environmental impacts. The applicant has identified the following limitations:

a) Reduced power output.
b) Emissions of unreacted ammonia (slip).
c) Disposal of hazardous waste generated (spend catalyst).
d) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
e) Cost effectiveness for the application of SCR technology to the Kissimmee Utility project was considered to be $9,879 per ton of NO_x removed for the PG7111EA and $13,700 per ton of NO_x removed for the LM6000 when burning natural gas.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics.

In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products, Inc.), the following statement was made:

> "In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

For fuel oil firing, the cost associated with controlling NO_x emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this is the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_X injection ratio. For natural gas firing operation, NO_X emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater ammonia injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_X can be controlled with efficiencies ranging from 60 to 80 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NO_X emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

The applicant has indicated that the total levelized annual operating cost to install SCR for this project at 100 percent capacity factor and burning natural gas is $2,944,000 for the PG7111EA and $1,589,000 for the LM6000. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

For the PG7111EA combined cycle combustion turbine, based on the information supplied by the applicant, it is estimated that the maximum annual NO_X emissions using low NO_X burner will be 372 tons/year (natural gas) and 700 tons/year (oil firing). Assuming that SCR would reduce the NO_X emissions by 80%, about 74 tons of NO_X (natural gas) and 140 tons of NO_X (oil) would be emitted annually. When this reduction (298 TPY natural gas and 560 TPY oil) is taken into consideration with the total levelized annual operating cost of $2,944,000 (natural gas) and $3,424,000 (oil firing); the cost per ton of controlling NO_X is $9,879 (natural gas) and $6,114 (oil), respectively. These calculated costs are higher than has previously been approved as BACT.

For the simple cycle combustion turbine, based on the information supplied by the applicant, it is estimated that the maximum annual NO_X emissions using water injection will be 145 tons/year (natural gas) and 250 tons/year (oil firing). Assuming that SCR would reduce the NO_X emissions by 80%, about 29 tons of NO_X (natural gas) and 50 tons of NO_X (oil firing) would be emitted annually. When this reduction (116 TPY natural gas and 200 TPY oil) is taken into consideration with the total levelized annual operating cost of $1,589,000 (natural gas) and $1,840,000 (oil firing); the cost per ton of controlling NO_X is $13,700 (natural gas) and $9,200 (oil), respectively. These calculated costs are higher than has previously been approved as BACT.

A review of the latest DER BACT determinations show limits of 15 ppmvd (natural gas) using low-NO_x burn technology for combined cycle turbines. General Electric is currently developing programs using both steam/water injection and dry low NO_x combustor to achieve NO_x emission control level of 9 ppm when firing natural gas. Therefore, since this technology will be available by 1997, the Department has accepted the water injection (LM6000), low NO_x burner design (PG7111EA), and the 25 ppmvd (natural gas)/42 ppmvd (oil) at 15% O_2 as BACT for a limited time (up to 1/1/98).

Sulfur Dioxide(SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant has stated that sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions when firing fuel oil will be controlled by using fuel oil with a maximum sulfur content of 0.05 % by weight. This will result in an annual emission rate of 18 tons SO_2 per year and 2 tons H_2SO_4 mist per year (operating at 500 hours per year).

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emissions from stationary gas turbines is considered unreasonable."(23). EPA reinforced this point when, later on in the preamble, they stated that "FGD... would cost about two to three times as much as the gas turbine."(23). The economic impact of applying FGD today would be no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the open literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option then leaves the use of low sulfur fuel oil as the next option to be investigated. Kissimmee Utility Authority, as stated above, has proposed the use of No. 2 fuel oil with a 0.05% sulfur by weight as BACT for this project. The Department accepts their proposal as BACT for this project.

BACT Determination by DER

NO_x Control

The information that the applicant presented and Department calculations indicates that the cost per ton of controlling NO_x for these turbines [$9,879 (gas) PG7111EA, $6,114 (oil) PG7111EA, $13,700 (gas) LM6000, and $9,200 (oil) LM6000] is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT at this time.

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, and various capacity factors). Although, the cost and other concerns expressed by the applicant are valid, the Department, in this case, is willing to accept water injection and low NO_x burner design as BACT for this project for a limited time (up to 12/31/97).

It is the Department's understanding that General Electric is developing programs for the PG7111EA and the LM6000, using either steam/water injection or dry low NO_x combustor technology to achieve a NO_x emission control level of 9 ppm when firing natural gas. Therefore, the Department has determined that the following BACT will apply by 1/1/98.

a) For the combined cycle unit (PG7111EA), if the 15 (gas)/42 (oil) ppmv emission rates cannot be met by 1/1/98, SCR will be installed. Hence, the permittee shall install a duct module suitable for future installation of SCR equipment.
b) For the simple cycle unit (LM6000), the manufacturer will attempt to achieve a maximum NO_x emission level of 15 (gas)/42 (oil) ppmv by 1/1/98. Should this level of control not be achieved, the permittee must notify the Department of the expected compliance date by 1/1/97.
c) For both turbines (PG7111EA and LM6000), when the manufacturer achieves an even lower NO_x emission level than 15 (gas)/42 (oil) ppmv, this level may become a condition of this permit.

SO_2 Control

BACT for sulfur dioxide is the burning of fuel oil No. 2 with 0.05% sulfur content by weight.

VOC and CO Control

Combustion control will be considered as BACT for CO and VOC when firing natural gas.

Other Emissions Control

The emission limitations for PM and PM_{10}, Be, Pb, and Hg are based on previous BACT determinations for similar facilities.

The emission limits for Kissimmee Utility Authority project are thereby established as follows:

120 MW COMBINED CYCLE COMBUSTION TURBINE

Pollutant	Emission Standards/Limitations Oil(a)	Gas(b)	Method of Control
NO_x	42 ppmv	25 ppmv(c)	Water Injection/ Quiet Combustor or Dry Low NO_x Combustor
		15 ppmv	Water Injection/Dry Low NO_x Combustor
CO	65 lbs/hr	54 lbs/hr	Combustion
PM & PM10	15 lbs/hr	7 lbs/hr	Combustion
SO_2	52 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
H_2SO_4	5.7 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
VOC	5 lbs/hr	2 lbs/hr	Combustion
Hg	3.0×10^{-6} lb/MMBtu		Fuel Quality
Pb	2.8×10^{-5} lb/MMBtu		Fuel Quality
Be	2.5×10^{-6} lb/MMBtu		Fuel Quality

(a) No. 2 fuel oil with a maximum of 0.05% sulfur by weight.
(b) Natural gas/fuel oil 8260/500 hours per year. Natural gas/fuel oil 7760/1000 hours per year. Continuous burning of No. 2 fuel oil (8760 hrs/yr) is not allowed unless natural gas is not available.
(c) Initial NO_x emission rates for natural gas firing shall not exceed 25 ppmvd at 15% oxygen on a dry basis. The permittee shall achieve NO_x emissions of 15 ppmvd at 15% oxygen at the earliest achievable date based on dry low NO_x combustor

injection technology or any other technology available, but no later than 1/1/98. Should this level of control not be achieved, the permitte shall install SCR.

40 MW SIMPLE CYCLE COMBUSTION TURBINE

Pollutant	Emission Standards/Limitations Oil[(a)]	Gas[(b)]	Method of Control
NO_x	42 ppmv	25 ppmv[(c)] 15 ppmv	Water Injection Dry Low NO_x Combustor
CO	76 lbs/hr	40 lbs/hr	Combustion
PM & PM10	12 lbs/hr	9 lbs/hr	Combustion
SO_2	20 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
H_2SO_4	2.2 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
VOC	3 lbs/hr	1.4 lbs/hr	Combustion
Hg	3.0×10^{-6} lb/MMBtu		Fuel Quality
Pb	2.8×10^{-5} lb/MMBtu		Fuel Quality
Be	2.5×10^{-6} lb/MMBtu		Fuel Quality

(a) No. 2 fuel oil with a maximum of 0.05% sulfur by weight.
(b) Natural gas/fuel oil 8260/500 hours per year. Natural gas/fuel oil 7760/1000 hours per year. Continuous firing of fuel oil (8760 hrs/yr) is not allowed unless natural gas is not available.
(c) Initial NO_x emission rates for natural gas firing shall not exceed 25 ppmvd at 15% oxygen on a dry basis. The permittee shall achieve NO_x emissions of 15 ppmvd at 15% oxygen at the earliest achievable date based on dry low NO_x combustor technology or any other technology available, but no later than 1/1/98. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with the expected compliance dates which will be updated annually. After 1/1/98, if the compliance schedule has not been met, the Department may require SCR be installed since the exhaust temperature has an acceptable range for SCR installation.

Details of the Analysis May be Obtained by Contacting:

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Recommended by:

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Bureau of Air Regulation

April 1, 1993
Date

Approved by:

Virginia B. Wetherell
Virginia B. Wetherell, Secretary
Dept. of Environmental Regulation

April 7, 1993
Date