Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

August 26, 2004

CERTIFIED MAIL – Return Receipt Requested

Mr. Alex C. George
V.P. and Responsible Official
Hardee Power Partners (A Subsidiary of Invenergy, LLC)
P.O. Box 111
Tampa, Florida 33601-0111

Re: PROPOSED Title V Air Operation Permit Renewal No.: 0490015-005-AV
Hardee Power Station

Dear Mr. George:

One copy of the "PROPOSED Determination" for the Hardee Power Station located at 6695 County Road 663, Fort Green Springs, Hardee 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 provided to the United States Environmental Protection Agency (USEPA) Region 4 office for their review.

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 Title V Permit Renewal was mailed (posted) to USEPA. If USEPA has an objection to the PROPOSED Permit, the FINAL Permit will not be issued until the permitting authority receives written notice that the objection is resolved or withdrawn.

If you should have any questions, please contact Bruce Mitchell at 850/413-9198.

Sincerely,

Trina L. Vielhauer
Chief
Bureau of Air Regulation

TLV/rbm

Enclosures

Copy furnished to:
Mr. Jason Waters, FDEP, SWD
Mr. Byron Burrows, P.E., TECO Power Services
Mr. Hamilton Oven, P.E., FDEP-SCO
U.S. EPA, Region 4 (INTERNET E-mail Memorandum)

U.S. Postal Service

CERTIFIED MAIN RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

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Mr. Alex C. George, V.P. & R.O.

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Sent To
Mr. Alex C. George, V.P. & R.O.

Street, Apt. No.; or PO Box No. P.O. Box 111

City, State, ZIP+4 Tampa, Florida 33601-0111

PS Form 3800, January 2001 See Reverse for Instructions

PROPOSED Determination

Hardee Power Partners (A Subsidiary of Invenergy, LLC)
Hardee Power Station
Title V Air Operation Permit Renewal
PROPOSED Permit No.: 0490015-005-AV
Facility ID No.: 0490015

I. Public Notice.

An "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL" to the Hardee Power Station located at 6695 County Road 663, Fort Green Springs, Hardee County, was clerked on June 24 2004. The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT RENEWAL" (DRAFT)" was published in the Highlands Today & The Tampa Tribune on July 10, 2004. The DRAFT Permit was available for public inspection at the Department's Southwest District office and the permitting authority's office in Tallahassee. Proof of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR OPERATION PERMIT RENEWAL" was received on July 16, 2004.

II. Public Comments.

Comments were received during the 30 (thirty) day public comment period on August 9, 2004, from Mr. Alex C. George, V.P. and Responsible Official. The comments are not significant, such that the changes made do not require another Public Notice. The comments will not be restated and are addressed as they were presented in the attached letter.

A. Comments from Mr. Alex C. George, received on August 9, 2004.

1. Because Combustion Turbine 2B is an Acid Rain unit, the Title IV permit, which is a part of the Title V permit, must be issued for a 5 year period and shall have an effective date of January 1 of a given year; and, that is the way that the dates in the DRAFT permit have been established. Therefore, no changes will be made.

2. The request is acceptable and the lead off statement of "Subject to EPA approval," will be deleted in Specific Condition B.17., because EPA's canned language for "Custom Fuel Monitoring for Natural Gas" is contained in the Specific Condition. However, realize that the sulfur content cannot be greater than 2 grains /100 cubic feet, based on BACT, which is reflected in Specific Conditions B.2. and B.17.(d)(2).

3. Based on the request, the lead-in sentence of Specific Condition B.17. has been numbered as "1.", which was assumed, but never numbered as such.

4. The request is acceptable and "TECO Power Services" has been replaced with "Hardee Power Partners" on the cover page of Appendix CAM.

5. The request is acceptable and in Table 1. Monitoring Approach. Part II. Indicator Range., the proposed changes have been incorporated to better reflect how and when alarms are generated by the Mark IV turbine control system as follows:
FROM:

II. Indicator Range	An excursion is defined as any 1-minute average that the water-to-fuel ratio falls below the level indicated by the heat input curves shown in figures 1 – 6 (typical target values for different load percentages are shown in Table 2), below. If there is a problem with fuel or water flow that causes the actual ratio to fall below the target during any 1-minute averaging period, an alarm notifies the control room staff of the problem. Since the data is monitored in 1-minute averages and the compliance standard is based on 1-hour averages, the alarms allow the operating staff to investigate the cause and take corrective action prior to having a non-compliant situation.

TO:

II. Indicator Range	An excursion is defined as any 4 consecutive 1-minute averages that the water-to-fuel ratio falls below the level calculated by the Mark IV based on algorithms programmed into the system to account for varying ambient conditions relevant to proper control. These calculations incorporate the water injection curves shown in figures 1 – 6 (typical target values for different load percentages are shown in Table 2), below. If there is a problem with fuel or water flow that causes the actual ratio to fall below the target during any 4 consecutive 1-minute averages, an alarm notifies the control room staff of the problem. Since the data is monitored in 4 consecutive 1-minute averages and the compliance standard is based on 1-hour averages, the alarms allow the operating staff to investigate the cause and take corrective action prior to having a non-compliant situation.

III. Conclusion.
The permitting authority hereby issues the PROPOSED Permit, with any changes noted above.

STATEMENT OF BASIS
Hardee Power Partners (A Subsidiary of Invenergy, LLC)
Hardee Power Station
Facility ID No.: 0490015
Hardee County

Title V Air Operation Permit Renewal
PROPOSED Permit No.: 0490015-005-AV

This Title V Air Operation Permit Renewal 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 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. The existing Hardee Power Station is located at 6695 County Road 663, Fort Green Springs, in Hardee County; UTM Coordinates: Zone 17, 404.8 km East and 3,057.4 km North; Latitude: 22° 38' 02" North and Longitude: 81° 38' 02" West.

Hardee Power Partners (A Subsidiary of Invenergy, LLC), operates a nominal 370 megawatt (MW) electric generation facility located approximately nine miles northwest of Wauchula in Hardee County, Florida. The Hardee Power Station includes four General Electric (GE) dual-fuel fired combustion turbines (CTs). The facility utilizes pipeline natural gas as its primary fuel source, with No. 2 distillate fuel oil serving as a backup fuel.

Three of the CTs (CT-1A, CT-1B and CT-2A) are identical emissions units, GE Model No. PG-7111 EA, and CTs 1A and 1B together comprise a combined-cycle unit operation and CT 2A is a simple cycle unit operation. All of the CTs have a nominal power production output of 75 MW; and, for CTs 1A and 1B, each has a generator nameplate rating of 113 MW (total of the CT and associated HRSG). CT-1A and CT-1B are each equipped with a heat recovery steam generator (HRSG), which feed one common steam turbine (ST). CT-1A and CT-1B are each equipped with a stack to bypass each unit's HRSG. The maximum permitted heat input rate to each CT is 1,312.3 MMBtu/hr while firing oil, and 1,268.4 MMBtu/hr while firing natural gas. Water injection is used to reduce NO_x emissions when firing natural gas and low sulfur distillate oil (backup fuel). These emission units are regulated under Rule 62-210.300, F.A.C., Permits Required; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(8), F.A.C.; NSPS - 40 CFR 60, Subpart A; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration; PSD-FL-140; and, these units are not affected by the Acid Rain Program since they meet the requirements of 40 CFR 72.6(b)(6). Continuous Assurance Monitoring (CAM) applies for NO_X.

The fourth and latest CT (CT-2B) is also manufactured by GE, Model No. PG-7121 (7EA), and is a simple cycle unit operation. The CT has an electrical generator with a nominal power production output of 75 MW. Dry low-NO_x (DLN) combustion technology will be used to control nitrogen oxide emissions, when firing the primary fuel of pipeline natural gas. Water injection will be used to control NO_x emissions, when firing low sulfur distillate oil as a backup fuel. Combustion design and clean fuels will be used to minimize emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC. This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(8), F.A.C.; NSPS - 40 CFR 60, Subpart A; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration; Rule 62-212.400(6), F.A.C. (BACT); PSD-FL-140A; and, the applicable provisions of the Acid Rain Program.

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

Based on the renewal Title V permit application received December 22, 2003, this facility is a major source of hazardous air pollutants (HAPs).

Hardee Power Partners (A Subsidiary of Invenergy, LLC)
Hardee Power Station
Facility ID No. 0490015
Hardee County

Title V Air Operation Permit Renewal
PROPOSED Permit No.: 0490015-005-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

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

Telephone: 850/488-0114
Fax: 850/922-6979
Fax: 850/921-9533

Compliance Authority:
Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218

Title V Air Operation Permit Renewal
PROPOSED Permit No.: 0490015-005-AV

Table of Contents

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

Permittee:
Hardee Power Partners
A Subsidiary of Invenergy, LLC
P.O. Box 111
Tampa, Florida 33602

PROPOSED Permit No. 0490015-005-AV
Facility ID No. 0490015
SIC Nos. 49, 4911
Project: Title V Air Operation Permit Renewal

This permitting action is for the renewal of the Title V Air Operation Permit. The Hardee Power Station is located at 6695 County Road 663 North, Fort Green Springs, in Hardee County; UTM Coordinates: Zone 17, 405.02 km East and 3,057.18 km North; Latitude: 27° 38' 13" North and Longitude: 81° 57' 45" West.

This Title V Air Operation Permit renewal 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 G-1, Manufacturer's Performance Curves
Appendix U-1, List of Unregulated Emissions Units and Activities
Appendix I-1, List of Insignificant Emissions Units and Activities
APPENDIX TV-4, TITLE V CONDITIONS (version dated 02/12/02)
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 07/96)
Appendix CAM

Effective Date: January 1, 2005
Renewal Application Due Date: July 5, 2009
Expiration Date: December 31, 2009

Michael G. Cooke, Director
Division of Air Resource Management

MGC/jkp/bm

Section I. Facility Information.

Subsection A. Facility Description.

Hardee Power Partners (A Subsidiary of Invenergy, LLC), operates a nominal 370 megawatt (MW) electric generation facility located approximately nine miles northwest of Wauchula in Hardee County, Florida. The Hardee Power Station includes four General Electric (GE) dual-fuel fired combustion turbines (CTs). The facility utilizes pipeline natural gas as its primary fuel source, with No. 2 distillate fuel oil serving as a backup fuel. Three of the CTs (CT-1A, CT-1B and CT-2A) are identical emissions units, GE Model No. PG-7111EA, and CTs 1A and 1B together comprise a combined-cycle unit operation and CT 2A is a simple cycle unit operation. All of the CTs have a nominal power production output of 75 MW; and, for CTs 1A and 1B, each has a generator nameplate rating of 113 MW (total of the CT and associated HRSG). CT-1A and CT-1B are each equipped with a heat recovery steam generator (HRSG), which feed one common steam turbine (ST). CT-1A and CT-1B are each equipped with a stack to bypass each unit's HRSG. The maximum permitted heat input rate to each CT is 1,312.3 MMBtu/hr while firing oil, and 1,268.4 MMBtu/hr while firing natural gas. Water injection is used to reduce NO_x emissions when firing natural gas and low sulfur distillate oil (backup fuel). The fourth and latest CT (CT-2B) is also manufactured by GE, Model No. PG-7121 (7EA), and is a simple cycle unit operation. The CT has an electrical generator with a nominal power production output of 75 MW. Dry low-NO_x (DLN) combustion technology will be used to control nitrogen oxide emissions, when firing the primary fuel of pipeline natural gas. Water injection will be used to control NO_x emissions, when firing low sulfur distillate oil as a backup fuel. Combustion design and clean fuels will be used to minimize emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC.

Compliance Assurance Monitoring (CAM) is applicable to CTs 1A, 1B and 2A, for NO_X.

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

Based on the renewal Title V permit application received December 22, 2003, this facility is a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Units

E.U. ID No.	Brief Description
001	CT-1A with an associated unfired HRSG
002	CT-1B with an associated unfired HRSG
003	CT-2A
004	CT-2B

Subsection C. Relevant Documents

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

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

These documents are on file with the permitting authority:
Title V Permit Renewal Application received December 22, 2003
Mr. Byron Burrows' e-mail with attachment (water injection system for CTs 1A, 1B and 2A) received January 21, 2004.
Mr. Byron Burrows' letter and Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)) received January 22, 2004.
RAI dated February 18, 2004.
Mr. Byron Burrows' e-mail with attachments received June 4, 2004.
Mr. Alex C. George's letter with enclosure received August 9, 2004.

Section II. Facility-wide Conditions

The following conditions apply facility-wide:

1. APPENDIX TV-4, TITLE V CONDITIONS, is a part of this permit.
{Permitting Note: APPENDIX TV-4, TITLE V CONDITIONS, is distributed to the Permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. **Not federally enforceable.** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

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.]

{Permitting Note: Although the Permittee is not required to perform a visible emissions compliance test to demonstrate compliance with the facility-wide limitations annually or before renewal, if the Department believes that the general visible emissions standard is being violated, the Department may require that the owner or operator perform a visible emissions compliance test per Chapter 62-297.310(7)(b), Special Compliance Tests.}

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 1515
Lanham-Seabrook, MD 20703-1515
Telephone: 301/429-5018

and,
b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

5. Unregulated Emissions Units and 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.

{Permitting Note: **"Nothing was deemed necessary and ordered at this time."**}

[Rule 62-296.320(1)(a), F.A.C.]

8. Reasonable precautions shall be taken to prevent emissions of unconfined particulate matter at this facility as necessary.
[Rule 62-296.320(4)(c)2., F.A.C.]

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 to the Department's Southwest District office:

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

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

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155
Fax: 404/562-9164

12. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of APPENDIX TV-4, TITLE V CONDITIONS)}

13. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), F.A.C.]

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

Section III. Emissions Units and Conditions.

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

E.U. ID No.	Brief Description
001	Combustion Turbine -1A (CT-1A) with an associated unfired HRSG
002	CT-1B with an associated unfired HRSG
003	CT-2A

These emissions units are three identical General Electric (GE) Model No. PG-7111EA dual-fuel fired CTs (CT-1A, CT-1B and CT-2A), each having a nominal power production output of 75 MW; and, for CTs 1A and 1B, each has a generator nameplate rating of 113 MW (total of the CT and associated HRSG). CT-1A and CT-1B are each equipped with an associated unfired heat recovery steam generator (HRSG), which feed one common steam turbine (ST). CT-1A and CT-1B are each equipped with a stack to bypass each unit's HRSG. CTs 1A and 1B comprise a combined-cycle unit operation and CT 2A is a simple cycle unit operation. CAM applies for NO_X.

The facility utilizes pipeline natural gas as its primary fuel source with No. 2 distillate fuel oil serving as a backup fuel. The maximum annual average of the fuel oil sulfur content is 0.3%, by weight, and the maximum fuel oil sulfur content is 0.5%, by weight. Water injection is used to reduce NO_x emissions; and, the water-to-fuel ratio is required to be continuously monitored for NO_X purposes. The maximum permitted heat input rate to each CT is 1,312.3 MMBtu/hr, while firing oil, and 1,268.4 MMBtu/hr, while firing natural gas.

Exhaust gases from the CTs exit a 90 foot high stack (14.5 feet diameter) at approximately 245 °F, with an actual volumetric flow rate of 751,000 acfm. These parameters are based on firing natural gas at 100% base load.

{Permitting Notes: These emission units are regulated under Rule 62-210.300, F.A.C., Permits Required; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(8), F.A.C.; NSPS - 40 CFR 60, Subpart A; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration; PSD-FL-140; and, the emissions units are **not** affected by the Acid Rain Program since they meet the requirements of 40 CFR 72.6(b)(6).}

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

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum heat input to each CT, at an ambient temperature of 32° F, shall not exceed 1,312.3 MMBtu/hr, while firing fuel oil, nor 1,268.4 MMBtu/hr, while firing natural gas. [PSD-FL-140]

A.2. Methods of Operation - Fuels. The only fuels allowed to be burned in these emissions units are natural gas or No. 2 fuel oil. The annual average sulfur content of the fuel oil shall not exceed 0.3 percent, by weight; and, the maximum sulfur content shall not exceed 0.5%, by weight.
[Rule 62-213.440(1), F.A.C.; and, PSD-FL-140]

A.3. Hours of Operation.
These emissions units are allowed to operate continuously, i.e., 8,760 hours per year.
[PSD-FL-140]

Emission Limitations and Standards

{Permitting Note: Unless otherwise specified, the averaging times for specific conditions **A.4.** thru **A.9.** are based on the specified averaging time of the applicable test method.}

A.4. Nitrogen Oxides. NO_x emissions from each CT shall not exceed:
a. 42 ppmvd at 15% O_2 and 215.9 lbs/hr, while firing natural gas; and,
b. 65 ppmvd at 15% O_2 and 383.8 lbs/hr, while firing fuel oil.
[PSD-FL-140]

A.5. Sulfur Dioxide. SO_2 emissions from each CT shall not exceed 35.8 lbs/hr, while firing natural gas, and 734.4 lbs/hr, while firing fuel oil.
[PSD-FL-140]

A.6. Particulate Matter (PM)/PM_{10}. PM/PM_{10} emissions from each CT shall not exceed 5 lbs/hr, while firing natural gas, and 10 lbs/hr, while firing fuel oil.
[PSD-FL-140]

A.7. Carbon Monoxide. CO emissions from each CT shall not exceed 10 ppmvd and 31.3 lbs/hr, while firing natural gas, and 26 ppmvd and 93.4 lbs/hr, while firing fuel oil.
[PSD-FL-140]

A.8. Volatile Organic Compounds. VOC emissions from each CT shall not exceed 2 ppmvd and 3.6 lbs/hr, while firing natural gas, and 5 ppmvd and 10.3 lbs/hr, while firing fuel oil.
[PSD-FL-140]

A.9. Visible Emissions. Visible emissions from each CT shall not exceed 10 percent opacity, while firing natural gas, and 20 percent opacity, while firing fuel oil.
[PSD-FL-140]

Monitoring Requirements

A.10. CMS Requirements. The Permittee shall install, operate, and maintain a continuous monitoring system (CMS) to monitor and record the fuel consumption, the ratio of water to fuel being fired in the turbine. The system shall be accurate to within ±5.0 percent and shall be approved by the Department.
[40 CFR 60.334(a); and, PSD-FL-140]

A.11. Critical Fuel Parameters. The Permittee shall monitor sulfur content and nitrogen content of the fuel being fired in the CTs. Pursuant to the custom monitoring schedule provisions of 40 CFR 60.334(b)(2), the frequency of determination of these values shall be as follows:
1. Monitoring of the nitrogen content of No. 2 fuel oil is not required. The sulfur content of distillate fuel oil shall be determined for each shipment of No. 2 fuel oil received; and,
2. Monitoring of the nitrogen content of pipeline natural gas is not required. The sulfur content of pipeline natural gas will be based on twice-monthly analyses provided by the natural gas supplier.
[40 CFR 60.334(b)(1) & (2)]

Test Methods & Procedures

A.12. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the manufacturer's rated heat input achievable for the average ambient (or conditioned) air temperature during the test. If it is impracticable to test at permitted capacity, then the emissions unit may be tested at less than permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. 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. If testing shows that NO_x emissions exceed the Subpart GG standard when operating at capacity, the Department may require a performance test in accordance with 40 CFR 60.335 testing procedures.
[Rule 62-4.070(3), F.A.C.; and, 40 CFR 60.8(a)]

A.13. 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 emissions 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.]

A.14. 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.]

A.15. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur.

Exceptions to these requirements are as follows:

a. (not applicable)
b. (not applicable)
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. (See attachment.)
(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.]

A.16. Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
[Rule 62-297.310(7)(b), F.A.C.; and, SIP approved]

A.17. Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7)(c), F.A.C.]

A.18. An annual compliance test shall be performed on each CT if the CT operated for more than 400 hours in the preceding 12-month period. Annual compliance tests shall be performed on the CTs while firing natural gas if No. 2 fuel oil was used for 400 hours or less in the preceding 12-month period. Annual compliance tests shall be performed on the CTs while firing No. 2 fuel oil if the No. 2 fuel was 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, as adopted by reference in Chapter 62-297, F.A.C.:
a. Reference Method 5, 5B or 17 for PM/PM_{10} (fuel oil only).
b. Reference Method 9 for VE.
c. Reference Method 10 for CO.
d. Reference Method 20 for NO_X.
e. Reference Method 25A for VOC.
f. Other methods may be used for compliance testing after obtaining prior Departmental approval, in writing.
[Rule 62-297.310(7)(a)(4), F.A.C.; and, PSD-FL-140]

A.19. Sulfur Content. The Permittee shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-96, or more recent version, shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-90(94)E-1, D 3031-81(86), D 4084-94, or D 3246-92, or more recent versions, shall be used for the sulfur content of gaseous fuels (incorporated by reference - see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Department.
[40 CFR 60.335(d); and, PSD-FL-140]

A.20. To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in 40 CFR 60.335(a) and 40 CFR 60.335(d) of 40 CFR 60.335 to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.
[40 CFR 60.335(e)]

Common Conditions

A.21. These emissions units are also subject to specific conditions **C.1.** through **C.19.**, contained in **Subsection C. Common Conditions.**

Special Conditions

A.22. On or before April 1 of each year, the Permittee shall submit to DARM and the Department's Southwest District Office an annual report for the previous year showing:
a. The annual average capacity factor (CF) for each individual generating unit;
b. The cumulative lifetime average CF for each individual generating unit;
c. The annual average CF for the Hardee Power Station; and,
d. The cumulative lifetime average CF for the Hardee Power Station.

The annual average CF shall be calculated by dividing each unit's megawatt hours output of generation by the product of the official megawatt rating of the unit and the number of hours in a year. Cumulative lifetime average CF shall be calculated by dividing the cumulative total of megawatt hours output of

generation by the product of the official combined cycle megawatt rating and the cumulative period of hours since commercial operation.
[PSD-FL-140]

A.23. To determine compliance with the capacity factor condition, the Permittee shall maintain daily records of power generation for each CT.
[PSD-FL-140]

A.24. Should any annual report demonstrate that the cumulative lifetime CF for the Hardee Power Station exceeds 60% at any time, the Permittee shall install SCR or another technology of equal or greater NO_x reduction capability. In no event shall any such SCR or equivalent NO_x control technology installation and compliance testing occur later than 30 months from the date that the Permittee requested or the facility exceeded the 60% cumulative average CF.
[PSD-FL-140]

A.25. If start/black start capability for the CTs is provided by a combustion unit, the Department shall be notified of the type and model, output capacity, anticipated hours of operation, and the air emissions of the unit.
[PSD-FL-140]

Miscellaneous

A.26. Modification. Any change in the method of operation, fuels, equipment, or phase design, shall be submitted for approval to the Department's permitting authority.
[Rules 62-210.300(1) & (1)(a); and, PSD-FL-140)

A.27. Sampling Facilities. Permanent stack sampling facilities shall be installed for the bypass stack (CT) and the main stack (HRSG) in accordance with Rule 62-297.310(6), F.A.C.
[Rules 62-204.800 and 62-297.310(6), F.A.C.; 40 CFR 60.8(e); and, PSD-FL-140]

Section III. Emissions Units and Conditions.

Subsection B. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
004	Combustion Turbine-2B (CT-2B)

This emissions unit is a General Electric Model No. PG-7121 (7EA), which is a dual-fuel fired CT with an electrical generator having a nominal power production output of 75 MW. Dry low-NO_x (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control NO_x emissions when firing low sulfur distillate oil as a backup fuel. Combustion design and clean fuels will be used to minimize emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC. CAM does not apply.

Exhaust gases from the CT will exit an 85 feet high rectangular stack (9 feet by 19 feet) at approximately 1000 °F with a volumetric flow rate of 1,465,518 acfm. These parameters are based on firing natural gas at 100% base load, cooling the CT inlet air to 59 °F, and ambient conditions of 60% relative humidity and 14.7 psi.

{Permitting Notes: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(8), F.A.C.; NSPS - 40 CFR 60, Subpart A; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration; Rule 62-212.400(6), F.A.C. (BACT); PSD-FL-140A; and, the applicable provisions of the Acid Rain Program.}

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

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The CT shall operate only in simple-cycle mode and generate a nominal 75 MW of electrical power. Operation of this emissions unit shall not exceed 880 MMBtu per hour of heat input from firing natural gas nor 950 MMBtu per hour of heat input from firing low sulfur distillate oil. The maximum heat inputs are based on the lower heating value (LHV) of each fuel, an inlet air supply cooled to 59 °F, a relative humidity of 60%, an ambient air pressure of 14.7 psi, and 100% base load. Therefore, maximum heat input rates will vary depending upon ambient conditions and the CT characteristics. Manufacturer's performance curves, corrected for site conditions or equations for correction to other ambient conditions, have been provided and are a part of this permit. See Attachment G-1.
[PSD-FL-140A]

B.2. Methods of Operation - Fuels. The CT shall be fired by pipeline natural gas containing no more than 2 grains of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, the CT may be fired with No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur content, by weight. Compliance with limits on fuel sulfur content shall be demonstrated by the record keeping requirements and/or the conditions of the Alternate Monitoring Plan specified in this permit. It is noted that these limitations are much more stringent than the NSPS sulfur dioxide limitation and assure compliance with 40 CFR 60.333 and 60.334. See specific conditions **B.9., B.15. thru B.17. and C.19.b.**
[PSD-FL-140A]

B.3. Hours of Operation. The hours of operation of the CT are not limited when firing natural gas (8760 hours per year). The CT shall not fire low sulfur distillate oil for more than 876 hours during any consecutive 12 months. Operation below 50% of baseline operation shall be limited to two (2) hours per unit cycle (breaker open to breaker closed).
[Rule 62-212.400(6), F.A.C. (BACT); and, PSD-FL-140A]

B.4. Simple Cycle Operation. The CT shall operate only in simple cycle mode. This requirement is based on the permittee's request, which formed the basis of the NO_x BACT determination and resulted in the emission standards specified in this permit. Specifically, the NO_x BACT determination eliminated several control alternatives based on technical considerations and costs due to the elevated temperatures of the exhaust gas. Any request to convert this unit to combined cycle operation by installing a new heat recovery steam generator or connecting this unit to an existing heat recovery steam generator shall require the permittee to perform a new NO_x BACT analysis and the approval of the Department through a permit modification. The results of this analysis may validate the initial BACT determination or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards.
[Rule 62-212.400(6)(b), F.A.C.; and, PSD-FL-140A]

Performance Restrictions

B.5. Operating Procedures. The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the CT and pollution control devices in accordance with the guidelines and procedures established by each equipment manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Rule 62-4.070(3), F.A.C.; Rule 62-212.400(6), F.A.C. (BACT); and, PSD-FL-140A]

B.6. Plant Operation - Problems. If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Compliance Authority as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations.
[Rule 62-4.130, F.A.C.; and, PSD-FL-140A]

Emission Limitations and Standards

{Permitting Note: Unless otherwise specified, the averaging times for specific conditions **B.7.**, **B.8.**, and **B.10.** thru **B.12.**, are based on the specified averaging time of the applicable test method.}

B.7. Nitrogen Oxides.
(a) Gas Firing: When firing natural gas in the CT, NO_X emissions shall not exceed 32.0 lbs/hr nor 9.0 ppmvd, corrected to 15% oxygen, based on a 3-hour test average. In addition, NO_X emissions shall not exceed 9.0 ppmvd, corrected to 15% oxygen, based on a 24-hour block average for data collected from the continuous emissions monitor.
(b) Oil Firing: When firing low sulfur distillate oil in the CT, NO_X emissions shall not exceed 167.0 lbs/hr nor 42.0 ppmvd, corrected to 15% oxygen, based on a 3-hour test average. In addition, NO_X emissions shall not exceed 42.0 ppmvd, corrected to 15% oxygen, based on a 3-hour block average for data collected from the continuous emissions monitor.

NO_x emissions are defined as emissions of oxides of nitrogen measured as NO_2. Compliance with the 3-hour (applicable during distillate fuel oil-firing) and 24-hour (applicable during natural gas-firing) block averages shall be demonstrated by collecting and reporting data in accordance with the conditions for the NO_x continuous emissions monitor specified by this permit.
[PSD-FL-140A]

B.8. Carbon Monoxide.
(a) Gas Firing: When firing natural gas in the CT, CO emissions shall not exceed 43.0 lbs/hr nor 20.0 ppmvd, corrected to 15% oxygen, based on a 3-hour test average.
(b) Oil Firing: When firing low sulfur distillate oil in the CT, CO emissions shall not exceed 43.0 lbs/hr nor 20.0 ppmvd, corrected to 15% oxygen, based on a 3-hour test average.
[PSD-FL-140A]

B.9. Sulfur Dioxide and Sulfuric Acid Mist (SAM). SO_2 and SAM emissions shall be limited by the good combustion techniques and the fuel sulfur limitations specified in this permit: natural gas containing no more than 2 grains of sulfur per 100 dry standard cubic feet of gas and No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur content, by weight.
[PSD-FL-140A]

B.10. Particulate Matter/PM_{10}. PM/PM_{10} emissions from the CT shall be limited by the good combustion techniques and the fuel sulfur limitations specified in this permit: natural gas containing no more than 2 grains of sulfur per 100 dry standard cubic feet of gas and No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur content, by weight.
[PSD-FL-140A]

B.11. Visible Emissions. As a surrogate for PM/PM_{10} emissions, visible emissions from the operation of the CT shall not exceed 10% opacity , based on a 6-minute average.
[PSD-FL-140A]

B.12. Volatile Organic Compounds (VOCs).
(a) Gas Firing: When firing natural gas in the CT, VOC emissions shall not exceed 2.0 lbs/hr nor 2.0 ppmvd, based on a 3-hour test average.
(b) Oil Firing: When firing low sulfur distillate oil in the CT, VOC emissions shall not exceed 5.0 lbs/hr nor 4.0 ppmvd, based on a 3-hour test average.

The VOC emissions shall be measured and reported in terms of methane.
[PSD-FL-140A]

Monitoring Requirements.

B.13. CMS Requirements. The permittee shall install, calibrate, operate and maintain a continuous monitoring system (CMS) to monitor and record the fuel consumption, the ratio of water to fuel being fired in the CT. The system shall be accurate to within ±5.0 percent and shall be approved by the Department. As an alternative to the monitoring requirements of this condition, the permittee may comply with the monitoring requirements of specific condition **B.17** (See Alternate Monitoring Plan).
[40 CFR 60.334(a)]

B.14. NO_x CEMS. The permittee shall install, calibrate, operate, and maintain a continuous emission monitoring system (CEMS) to measure and record NO_x and oxygen concentrations in the CT exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. NO_x data collected by the CEMS shall be used to demonstrate compliance with the 3-hour (applicable to distillate fuel oil-firing) and 24-hour (applicable to natural gas-firing) block emissions standards for NO_x. The block averages shall be determined by calculating the arithmetic average of all hourly emission rates for the respective averaging period. Each 1-hour average shall be expressed in units of ppmvd, corrected to 15% oxygen, and calculated using at least two valid data points at least 15 minutes apart. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction unless prohibited by Rule 62-210.700, F.A.C. (See specific condition **B.33.(b)**). When NO_x monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified averaging period.
(a) The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of: Rule 62-297.520, F.A.C., including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications 2 and 3; 40 CFR 60.7(a)(5); 40 CFR 60.13; 40 CFR 60, Appendix F; and, 40 CFR Part 75.
(b) Continuous emission monitoring data required by this permit shall be collected and recorded during all periods of operation including startup, shutdown, and malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Although recorded, emissions during periods of startup, shutdown and malfunction are subject to the excess emission conditions specified in this permit. When the CEMS reports NO_x emissions in excess of the standards allowed by this permit, the owner or operator shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. The Department may request a written report summarizing the excess emissions incident.
[Rules 62-204.800, 62-210.700, 62-4.130 and 62-4.160(8), F.A.C.; 40 CFR 60.7; and, PSD-FL-140A]

B.15. Critical Fuel Parameters. The Permittee shall monitor sulfur content and nitrogen content of the fuel being fired in the CT. Pursuant to the custom monitoring schedule provisions of 40 CFR 60.334(b)(2), the frequency of determination of these values shall be as follows:
1. Monitoring of the nitrogen content of No. 2 fuel oil is not required. The sulfur content of distillate fuel oil shall be determined for each shipment of No. 2 fuel oil received; and,
2. Monitoring of the nitrogen content of pipeline natural gas is not required. The sulfur content of pipeline natural gas will be based on twice-monthly analyses provided by the natural gas supplier.
[40 CFR 60.334(b)(1) & (2)]

Compliance Demonstrations

B.16. Fuel Records.
(a) Natural Gas. The permittee shall demonstrate compliance with the fuel sulfur limit for natural gas specified in this permit by maintaining records of the sulfur content of the natural gas being supplied for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81, or equivalent methods. These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule (see Alternate Monitoring Plan: specific condition **B.17.**) or natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75, Appendix D. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e). However, the permittee is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used to determine the fuel sulfur content for compliance with the 40 CFR 60.333 SO_2 standard.
(b) Low Sulfur Distillate Oil. For all bulk shipments of low sulfur distillate oil received at this facility, the permittee shall obtain from the fuel vendor an analysis identifying the sulfur content. Methods for determining the sulfur content of the distillate oil shall be ASTM D129-91, D2622-94, or D4294-90, or equivalent methods. Records shall specify the test method used and shall comply with the requirements of 40 CFR 60.335(d).
[Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

B.17. Alternate Monitoring Plan.
1. The following alternate monitoring may be used to demonstrate compliance.
(a) The NO_x CEMS data may be used in lieu of the monitoring system for water-to-fuel ratio and the reporting of excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG. Subject to EPA approval, the calibration of the water-to-fuel ratio-monitoring device required in 40 CFR 60.335(c)(2) will be replaced by the 40 CFR 75 certification tests of the NO_x CEMS.
(b) The NO_x CEMS data shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG.
(c) When requested by the Department, the CEMS emission rates for NO_x on this unit shall be corrected to ISO conditions to demonstrate compliance with the NO_x standard established in 40 CFR 60.332.
(d) A **custom fuel monitoring schedule** pursuant to 40 CFR 75, Appendix D, for natural gas, may be used in lieu of the daily sampling requirements of 40 CFR 60.334(b)(2) provided the following conditions are met.

(1) The permittee shall apply for an Acid Rain Permit within the deadlines specified in 40 CFR 72.30.

(2) The permittee shall submit a monitoring plan, certified by signature of the Authorized Representative, that commits to using a primary fuel of pipeline supplied natural gas containing no more than 2 grains of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2).

(3) Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).
[40 CFR 60, Subpart GG; and, PSD-FL-140A]

(e) The permittee shall monitor the sulfur contents of the No. 2 distillate fuel oil (or a superior grade) and natural gas. These values may be provided by the vendor and the frequency of determinations of these values shall be as follows:

a. No. 2 Distillate Fuel Oil (or a superior grade). The sulfur content shall be determined on each occasion that fuel is transferred to the storage tanks from any other source. Records of these values shall be kept by the facility for a five year period for regulatory agency inspection purposes.

b. Natural Gas. Pursuant to 40 CFR 60.334(b)(2), a custom fuel monitoring schedule for the determination of these values shall be followed for the natural gas fired at this facility and shall be as follows:

Custom Fuel Monitoring Schedule for Natural Gas

2. Sulfur Monitoring.

(a) Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are ASTM D1072-80, ASTM D3031-81, ASTM D3246-81, and ASTM D4084-82 as referenced in 40 CFR 60.335(b)(2), or the latest edition(s).

(b) This custom fuel monitoring schedule shall become effective on the date this permit becomes effective. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333 and the conditions of this permit, then sulfur monitoring shall be conducted once per quarter for six quarters. If monitoring data is provided by the applicant which demonstrates consistent compliance with the requirements herein the applicant may begin monitoring as per the requirements of paragraph 2(c), below.

(c) If after the monitoring required in paragraph 2(b), above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333 and the conditions of this permit, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

(d) Should any sulfur analysis as required in paragraphs 2(b) or 2(c), above, indicate non-compliance with 40 CFR 60.333 and the conditions of this permit, the owner or operator shall notify the Department of such excess emissions and the custom schedule shall be re-examined. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

3. If there is a change in fuel supply, the owner or operator must notify the Department of such change for re-examination of this custom schedule. A substantial change in natural gas quality (i.e., sulfur content varying by more than 10 grains/1000 dry standard cubic feet of gas) shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of five years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.
[40 CFR 60.334(b); and, PSD-FL-140A]

B.18. Monthly Operations Summary. By the fifth calendar day of each month, the owner or operator shall record the following information in a written (or electronic) log for the previous month of operation: the amount of hours each fuel was fired; the quantity of each fuel fired; the calculated average heat input of each fuel fired in MMBtu per hour, based on the lower heating value; and, the average sulfur content of each fuel. In addition, the owner or operator shall record the hours of oil firing for the previous 12 months of operation. The Monthly Operations Summary shall be maintained on site in a legible format available for inspection or printed at the Department's request.
[Rule 62-4.160(15), F.A.C.; and, PSD-FL-140A]

Test Methods & Procedures

B.19. Combustion Turbine Testing Capacity. Testing of emissions shall be conducted with the CT operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the authority to operate at the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C.
[Rules 62-4.070(3) and 62-297.310(2), F.A.C.; and, PSD-FL-140A]

B.20. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

B.21. 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.
[Rule 62-297.310(4)(a)1., F.A.C.]
2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
[Rule 62-297.310(4)(a)2., F.A.C.]
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
[Rule 62-297.310(4)(b), F.A.C.]

(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, F.A.C.
[Rules 62-297.310(4)(a), (b) & (d), F.A.C.]

B.22. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
[Rule 62-297.310(5)(a), F.A.C.]
(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)(b), F.A.C.]

B.23. Sampling Facilities. The permittee shall design the CT stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
[Rules 62-204.800 and 62-297.310(6), F.A.C.; and, 40 CFR 60.8(e)]

B.24. 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.]

B.25. Test Notification. The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial performance test and at least 15 days prior to any other required tests.
[Rule 62-297.310(7)(a)9., F.A.C.; 40 CFR 60.7; and, 40 CFR 60.8]

B.26. Annual Performance Tests. Annual performance tests for CO, NO_x, and visible emissions from the CT shall be conducted while firing natural gas if low sulfur distillate oil was used for 400 hours or less in the preceding 12-month period. Annual performance tests shall be conducted for CO, NO_x, and visible emissions from the CT while firing low sulfur distillate oil if the distillate oil was used for more than 400 hours in the preceding 12-month period. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). When conducted at permitted

capacity, the annual NO_x continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the annual compliance stack test.
[Rule 62-297.310(7)(a)4., F.A.C.]

B.27. Tests Prior to Permit Renewal. During the federal fiscal year (October 1st to September 30th) prior to renewing the air operation permit, the permittee shall also conduct individual performance tests for VOC emissions while firing natural gas and low sulfur distillate oil.
[Rule 62-297.310(7)(a)3., F.A.C.]

B.28. Tests After Substantial Modifications. All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shake-down period of air pollution control equipment including the replacement of dry low-NO_x combustors. Shakedown periods shall not exceed 100 days after re-starting the CT.
[Rule 62-297.310(7)(a)4., F.A.C.]

B.29. VE Tests After Shutdown. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions (VE) compliance test once per each five-year period, coinciding with the term of its air operation permit.
[Rule 62-297.310(7)(a)8., F.A.C.]

B.30. Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
[Rule 62-297.310(7)(b), F.A.C.; and, SIP approved]

B.31. Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7)(c), F.A.C.]

B.32. Performance Test Methods. Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.
(a) EPA Method 7E, "Determination of Nitrogen Oxide Emissions from Stationary Sources". This method may be used to determine compliance with the annual 3-hour NO_x limit.
(b) EPA Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" for VE.
(c) EPA Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" for CO. All CO tests shall be conducted concurrently with NO_x emissions tests.

(d) EPA Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." This test shall be used to determine compliance for the initial performance tests and may be used to determine compliance with the annual 3-hour NO_x limit.
(e) EPA Methods 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations."

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure pursuant to Rule 62-297.620, F.A.C.
[Rule 62-297.310(7)(a)(4), F.A.C.; and, PSD-FL-140A]

Excess Emissions

B.33. Excess Emissions.
(a) Excess Emissions Allowed. Excess emissions resulting from startup, shutdown, or malfunction of the CT shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions resulting from startup to simple cycle mode shall not exceed one (1) hour. In no case shall excess emissions from startup, shutdown, and malfunction exceed two hours in any 24-hour period. If excess emissions occur due to malfunction, the owner or operator shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and, the actions taken to correct the problem.
[Rule 62-210.700, F.A.C.; and, PSD-FL-140A]
(b) Excess Emissions Prohibited. Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 24-hour NO_X averages for compliance determinations.
[PSD-FL-140A]

Common Conditions

B.34. These emissions units are also subject to specific conditions **C.1.** through **C.19.,** contained in **Subsection C. Common Conditions**.

Miscellaneous

B.35. Modification. No emissions unit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification.
[Rules 62-210.300(1) & (1)(a); and, PSD-FL-140A)

B.36. New or Additional Conditions. For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time.
[Rule 62-4.080, F.A.C.; and, PSD-FL-140A]

Section III. Emissions Units and Conditions.

Subsection C. Common Conditions.

E.U. ID No.	Brief Description
001	CT-1A with an associated unfired HRSG
002	CT-1B with an associated unfired HRSG
003	CT-2A
004	CT-2B

Except as otherwise specified under Section III., Subsections A. through C., the following specific conditions apply to the emissions unit(s) listed above:

General Provisions - 40 CFR 60, Subpart A

C.1. Excess Emissions Reporting. If excess emissions occur due to malfunction, the owner or operator shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and, the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Following the NSPS format (40 CFR 60.7, Subpart A), periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards specified in this permit. Within thirty (30) days following each calendar quarter, the permittee shall submit a report on any periods of excess emissions that occurred during the previous calendar quarter to the Compliance Authority. This quarterly report shall follow the format provided in Figure 1 (see attached) of this permit.
[Rules 62-4.130, 62-204.800 and 62-210.700(6), F.A.C.; and, 40 CFR 60.7]

C.2. Quarterly Report. The Permittee shall submit a quarterly excess emissions and monitoring systems performance report. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

1. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
2. Specific identification of each period of excess emissions that occurs during startups, shutdowns and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
3. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
4. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[40 CFR 60.7(c)]

C.3. Summary Report. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Department. One summary report form shall be submitted for each pollutant monitored.

1. If the total duration of excess emissions for the reporting period is less than one percent of the operating time for the reporting period and CMS downtime for the reporting period is less than five 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 Department.
2. If the total duration of excess emissions for the reporting period is one percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is five 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.

[40 CFR 60.7(d)]

C.4. Reporting Frequency.

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

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods), the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under 40 CFR 60 continually demonstrate that the facility is in compliance with the applicable standard;

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

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

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

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the Permittee shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the Permittee may again request approval from the Department to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).

[40 CFR 60.7(e)]

C.5. Records Retention. The Permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least 5 (five) years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f); and, Rule 62-213.440(1)(b)2.b., F.A.C.]

C.6. If requested by the Department pursuant to specific conditions **A.12.** and **B.19.**, performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Subpart GG, unless the Department (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Department's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Department's authority to require testing under section 114 of the Act.
[40 CFR 60.8(b)(1), (4) & (5)]

C.7. If requested by the Department pursuant to specific conditions **A.12.** and **B.19.**, performance tests shall be conducted under such conditions as the Department shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Department such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
[40 CFR 60.8(c)]

C.8. Department Notification.
(a) The Permittee shall provide to the Department's Southwest District office at least 15 days prior notice of any compliance or performance test, except as specified under other subparts, to afford the District office the opportunity to have an observer present. Test results shall be submitted to the District office no later than 45 days after completion of the test.
[40 CFR 60.8(d); and, Rule 62-297.310(7)(a)8., F.A.C.]
(b) The Permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted timely and in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and, the anticipated completion date of the change.
[Rules 62-4.050(1) thru (7) and 62-4.070(1), F.A.C.]

Compliance with Standards and Maintenance Requirements

C.9. The Permittee shall follow the manufacturer's instructions during periods of start-up, shutdown, malfunction, or load change to ensure that the best operational practices to minimize emissions will be adhered to and the duration of any excess emissions will be minimized. The instructions shall be kept on file at the plant site and made available for inspection upon request by the Department.
[40 CFR 60.11(d)]

C.10. Credible Evidence. For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in 40 CFR 60, nothing in 40 CFR 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.
[40 CFR 60.11(g)]

C.11. Circumvention. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

Monitoring Requirements

C.12. After receipt and consideration of written application, the Department may approve alternatives to any monitoring procedures or requirements of 40 CFR 60 including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by 40 CFR 60 would not provide accurate measurements due to liquid water or other interferences caused by substances with the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the ASTM test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, 40 CFR 60, Appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Department may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities are released to the atmosphere through more than one point.

[40 CFR 60.13(i)]

Modifications

C.13. The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of 40 CFR 60 any other facility within that source.
[40 CFR 60.14(c)]

C.14. Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of this section.
[40 CFR 60.14(f)]

Additional Reporting and Recordkeeping Requirements

C.15. Annual Operating Report. The permittee shall submit the Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Department's Southwest District's Compliance Authority by March 1st of each year.
[Rule 62-210.370(3), F.A.C.]

C.16. Emissions Performance Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's Southwest District on the results of each such test.
(b) The required test report shall be filed with the Department's Southwest District 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 Department's Southwest District to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

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

Excess Emissions

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

C.17. Excess emissions from the CTs resulting from start-up, shutdown, malfunction, or load change shall be acceptable 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 a longer duration.
[Rule 62-210.700(1), F.A.C.]

C.18. Reserved. See specific condition **B.33.(b)**.

C.19. Excess Emissions Defined. For the purpose of reports required under 40 CFR 60.7(c) (see specific conditions **C.1.** through **C.4.**), periods of excess emissions that shall be reported are defined as follows:

a. *Nitrogen oxides*. For CT-1A, CT-1B and CT-2A, any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in 40 CFR 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

For CT-2B, NO_x CEMS data will be used in accordance with specific conditions **B.17.(a)** and **(b)**.

b. *Sulfur dioxide*. Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent, by weight.

[40 CFR 60.60.334(c)(1) & (2)]

Section IV. This section is the Acid Rain Part.

Operated by: Hardee Power Partners
ORIS Code: 50949
Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions unit listed below is regulated under Acid Rain, Phase II.

E.U. ID No.	Brief Description
004	Combustion Turbine-2B

A.1. The Phase II permit application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of this Phase II acid rain unit must comply with the standard requirements and special provisions set forth in the application listed below:
a. DEP Form No. 62-210.900(1)(a), dated/signed 12/22/03.
[Chapter 62-213 and Rule 62-214.320, F.A.C.]

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

E.U. ID No.	EPA ID	Year	2005	2006	2007	2008	2009
004	2B	SO_2 allowances, under Table 2 of 40 CFR Part 73	0*	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 of 40 CFR 73.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.
1. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
3. Allowances shall be accounted for under the Federal Acid Rain Program.
[Rule 62-213.440(1)(c), F.A.C.]

A.4. 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.5. Comments, notes, and justifications: None.

A.6. Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, Definitions - Applicable Requirements, F.A.C.]

Hardee Power Partners
Hardee Power Station
Facility ID #: 0490015

APPENDIX CAM

Compliance Assurance Monitoring Requirements

Compliance Assurance Monitoring Requirements

Pursuant to Rule 62-213.440(1)(b)1.a., F.A.C., the CAM plans that are included in this appendix contain the monitoring requirements necessary to satisfy 40 CFR 64. Conditions 1. – 17. are generic conditions applicable to all emissions units that are subject to the CAM requirements. Specific requirements related to each emissions unit are contained in the attached tables, as submitted by the applicant and approved by the Department.

40 CFR 64.6 Approval of Monitoring.

1. The attached CAM plan(s), as submitted by the applicant, is/are approved for the purposes of satisfying the requirements of 40 CFR 64.3.
[40 CFR 64.6(a)]

2. The attached CAM plan(s) include the following information:
   (i) The indicator(s) to be monitored (such as temperature, pressure drop, emissions, or similar parameter);
   (ii) The means or device to be used to measure the indicator(s) (such as temperature measurement device, visual observation, or CEMS); and
   (iii) The performance requirements established to satisfy 40 CFR 64.3(b) or (d), as applicable.
[40 CFR 64.6(c)(1)]

3. The attached CAM plan(s) describe the means by which the owner or operator will define an exceedance of the permitted limits or an excursion from the stated indicator ranges and averaging periods for purposes of responding to (see **CAM Conditions 5. - 9.**) and reporting exceedances or excursions (see **CAM Conditions 10. – 14.**).
[40 CFR 64.6(c)(2)]

4. The permittee is required to conduct the monitoring specified in the attached CAM plan(s) and shall fulfill the obligations specified in the conditions below (see **CAM Conditions 5. - 17.**).
[40 CFR 64.6(c)(3)]

40 CFR 64.7 Operation of Approved Monitoring.

5. Commencement of operation. The owner or operator shall conduct the monitoring required under this appendix upon the effective date of this Title V permit.
[40 CFR 64.7(a)]

6. Proper maintenance. At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[40 CFR 64.7(b)]

7. Continued operation. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the

operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.
[40 CFR 64.7(c)]

8. Response to excursions or exceedances.

a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions, if allowed by this permit). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 CFR 64.7(d)(1) & (2)]

9. Documentation of need for improved monitoring. If the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the Title V permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
[40 CFR 64.7(e)]

40 CFR 64.8 Quality Improvement Plan (QIP) Requirements.

10. Based on the results of a determination made under **CAM Condition 8.a.,** above, the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with **CAM Condition 4.**, an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, may require the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices.
[40 CFR 64.8(a)]

11. Elements of a QIP:

a. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.

b. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

(i) Improved preventive maintenance practices.
(ii) Process operation changes.
(iii) Appropriate improvements to control methods.
(iv) Other steps appropriate to correct control performance.
(v) More frequent or improved monitoring (only in conjunction with one or more steps under **CAM Condition 11.b(i)** through **(iv)**, above).

[40 CFR 64.8(b)]

12. If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

[40 CFR 64.8(c)]

13. Following implementation of a QIP, upon any subsequent determination pursuant to **CAM Condition 8.b.**, the permitting authority may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:
a. Failed to address the cause of the control device performance problems; or
b. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

[40 CFR 64.8(d)]

14. Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

[40 CFR 64.8(e)]

40 CFR 64.9 Reporting And Recordkeeping Requirements.

15. General reporting requirements.
a. On and after the date specified in **CAM Condition 5.** by which the owner or operator must use monitoring that meets the requirements of this appendix, the owner or operator shall submit monitoring reports semi-annually to the permitting authority in accordance with Rule 62-213.440(1)(b)3.a., F.A.C.
b. A report for monitoring under this part shall include, at a minimum, the information required under Rule 62-213.440(1)(b)3.a., F.A.C., and the following information, as applicable:
(i) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
(ii) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
(iii) A description of the actions taken to implement a QIP during the reporting period as specified in **CAM Conditions 10.** through **14.** Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[40 CFR 64.9(a)]

16. General recordkeeping requirements.
a. The owner or operator shall comply with the recordkeeping requirements specified in Rule 62-213.440(1)(b)2., F.A.C. The owner or operator shall maintain records of monitoring data,

monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to **CAM Conditions 10.** through **14.** and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

[40 CFR 64.9(b)]

40 CFR 64.10 Savings Provisions.

17. It should be noted that nothing in this appendix shall:

a. Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this appendix shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to title I of the Act. The purpose of this part is to require, as part of the issuance of a permit under Title V of the Act, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part.

b. Restrict or abrogate the authority of the Administrator or the permitting authority to impose additional or more stringent monitoring, recordkeeping, testing, or reporting requirements on any owner or operator of a source under any provision of the Act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable.

c. Restrict or abrogate the authority of the Administrator or permitting authority to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.

[40 CFR 64.10]

Hardee Power Station

Emissions Units -001, -002 & -003

Natural Gas and Oil-Fired Combustion Turbines
NO_X Emissions Controlled By Water Injection

Table 1. Monitoring Approach

		Compliance Indicator
I.	Indicator	Water-to-fuel ratio.
	Measurement Approach	Continuous Monitoring System measuring water injection rate, fuel consumption, and water-to-fuel ratio.
II.	Indicator Range	An excursion is defined as any 4 consecutive 1-minute averages that the water-to-fuel ratio falls below the level calculated by the Mark IV based on algorithms programmed into the system to account for varying ambient conditions relevant to proper control. These calculations incorporate the water injection curves shown in figures 1 – 6 (typical target values for different load percentages are shown in Table 2), below. If there is a problem with fuel or water flow that causes the actual ratio to fall below the target during any 4 consecutive 1-minute averages, an alarm notifies the control room staff of the problem. Since the data is monitored in 4 consecutive 1-minute averages and the compliance standard is based on 1-hour averages, the alarms allow the operating staff to investigate the cause and take corrective action prior to having a non-compliant situation.
III.	Performance Criteria A. Data Representativeness	The Mark IV combustion turbine control system continuously monitors the fuel flow rate and sends a signal to the water flow control valve to adjust the flow to meet the target ratio. The target ratio is calculated by the Mark IV based on algorithms programmed into the system to account for varying ambient conditions relevant to proper control.
	B. Verification of Operational Status	Annual compliance testing; and, reestablishment of the water-to-fuel ratio, if indicated by a failed compliance test.
	C. QA/QC Practices and Criteria	Operate and maintain the Mark IV combustion turbine control system according to manufacturer's specifications. All metering equipment, including transmitters, are calibrated annually and meet or exceed the minimum regulatory requirement of 5% accuracy.
	D. Monitoring Frequency	Continuous.
	E. Data Collection Procedures	The Mark IV combustion turbine control system continuously monitors the fuel flow rate and sends a signal to the water flow control valve to adjust the flow to meet the target ratio. The target ratio is calculated by the Mark IV based on algorithms programmed into the system to account for varying ambient conditions relevant to proper control.
	F. Averaging Period	1 minute.

Table 2. Typical Target Values for Water-to-Fuel Ratio

Load, percent	Water-to-Fuel Ratio Target Value When Firing Natural Gas			Water-to-Fuel Ratio Target Value When Firing Distillate Fuel Oil		
	CT-1A	CT-1B	CT-2A	CT-1A	CT-1B	CT-2A
50	0.45	0.43	0.31	0.55	0.36	0.37
75	0.58	0.56	0.50	0.60	0.40	0.40
90	0.66	0.64	0.59	0.65	0.52	0.55
100	0.71	0.69	0.69	0.69	0.63	0.68

FIGURE 1
UNIT 1A
WATER INJECTION CURVE FOR FUEL OIL

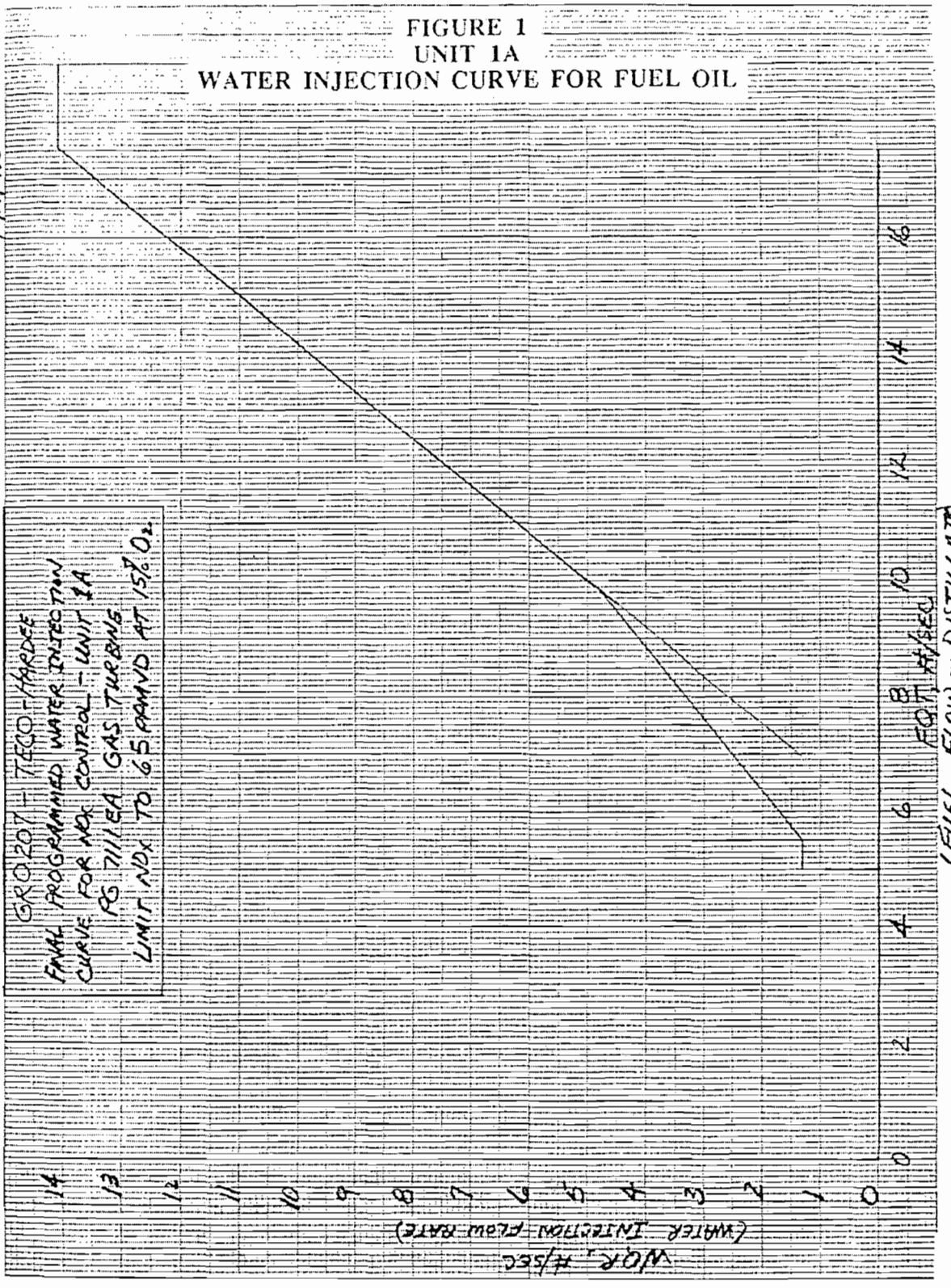


FIGURE 2
UNIT 1A
WATER INJECTION CURVE FOR NATURAL GAS

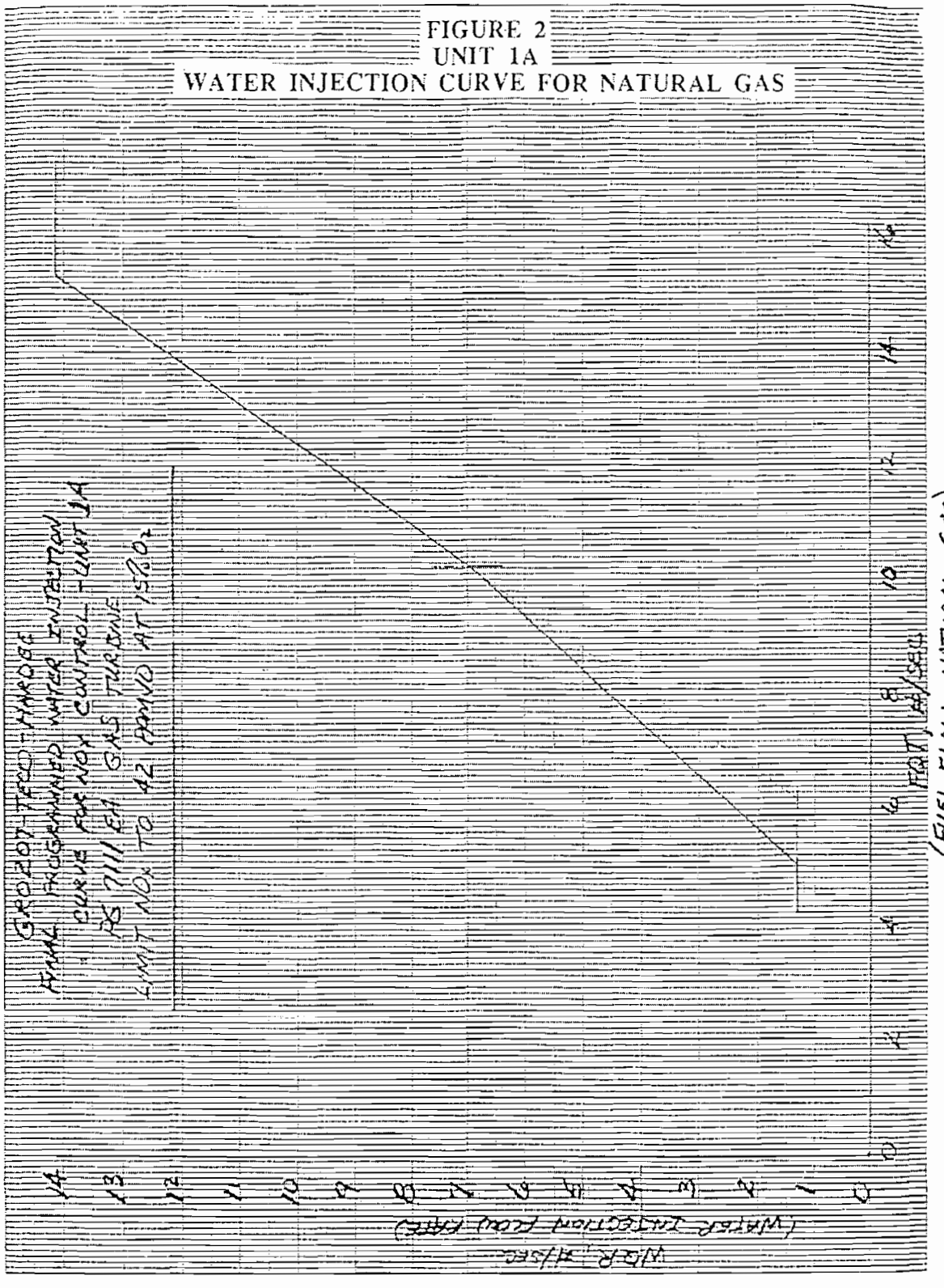


FIGURE 3
UNIT 1B
WATER INJECTION CURVE FOR FUEL OIL

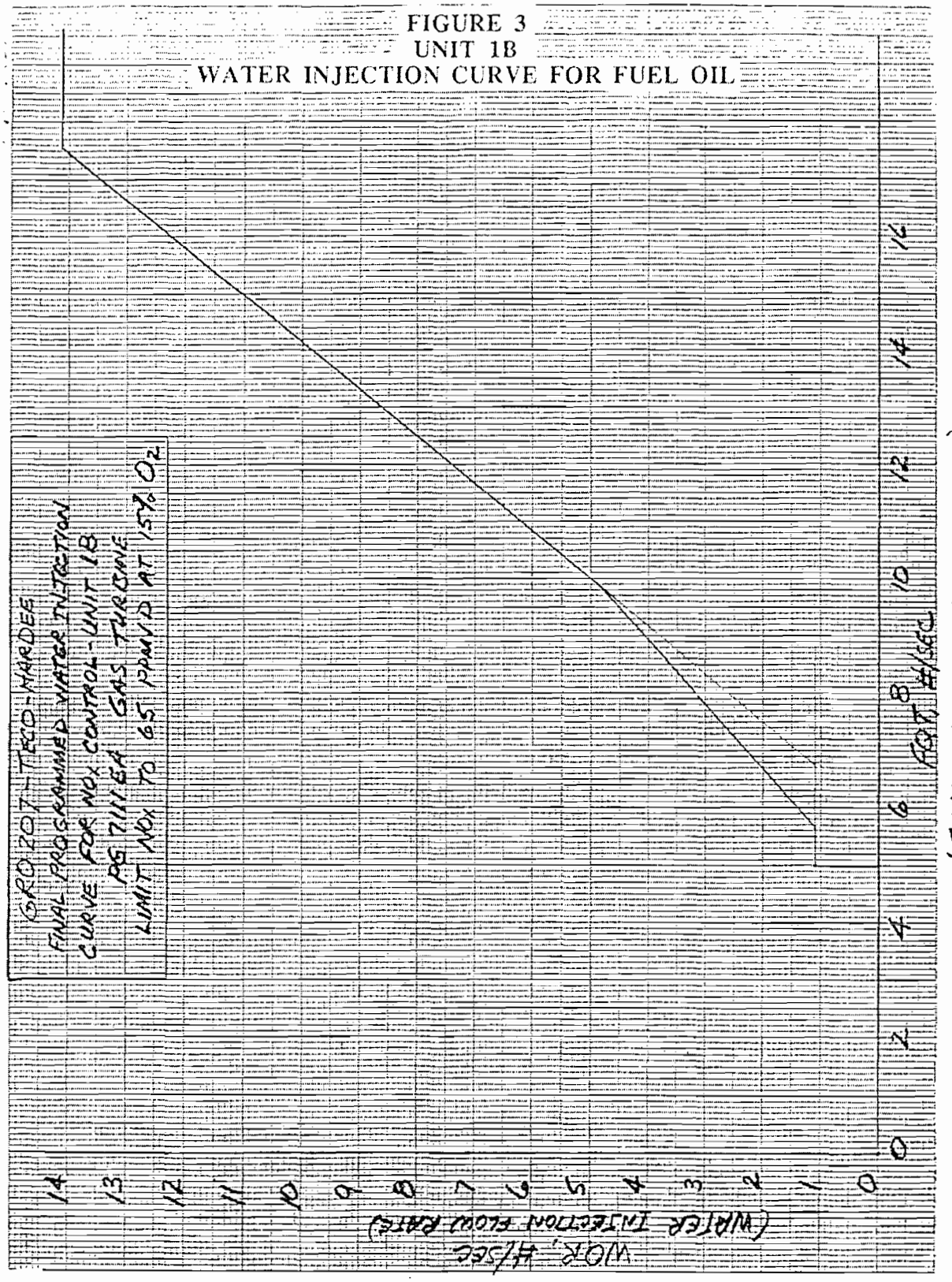


FIGURE 4
UNIT 1B
WATER INJECTION CURVE FOR NATURAL GAS

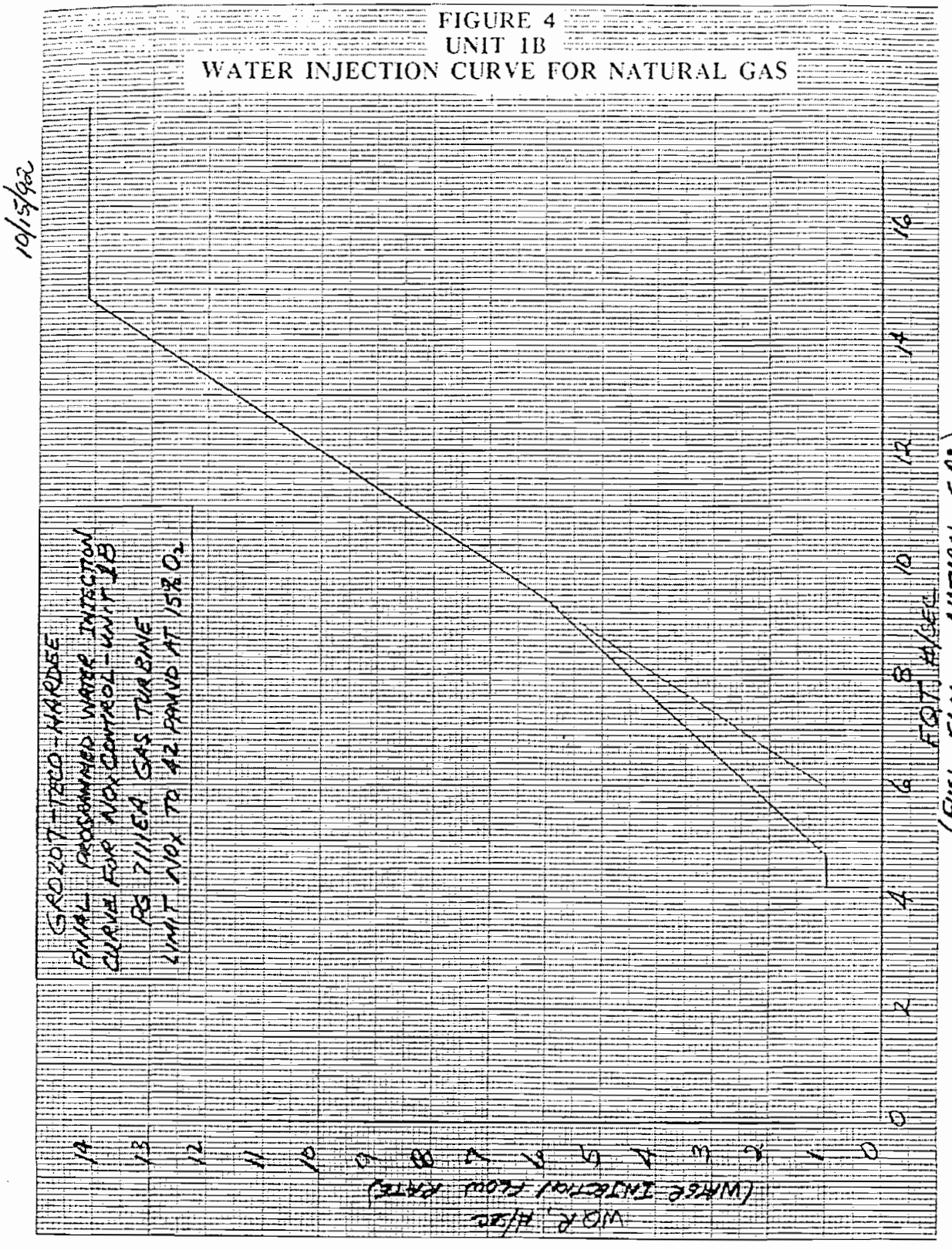


FIGURE 5
UNIT 2A
WATER INJECTION CURVE FOR FUEL OIL

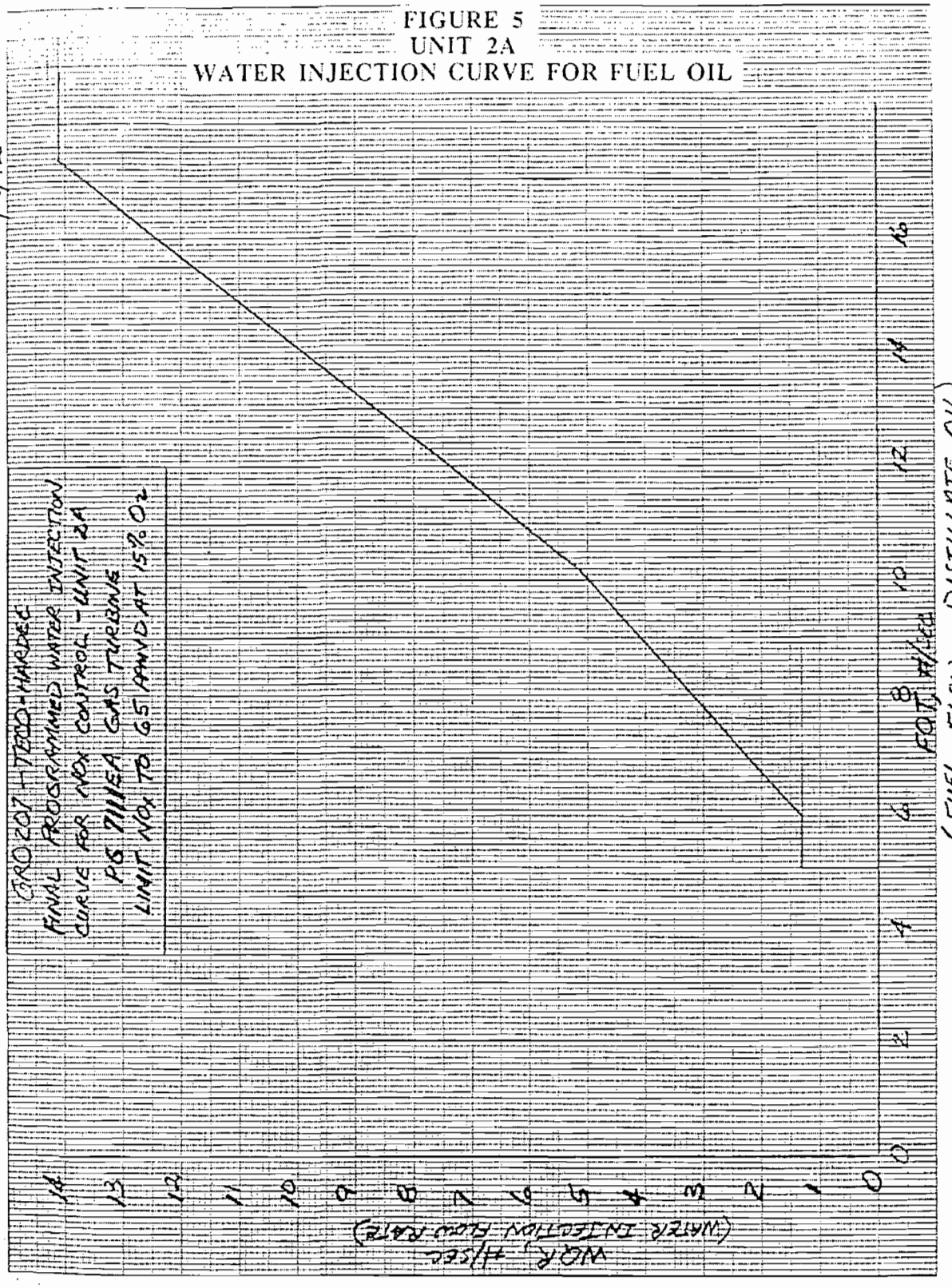
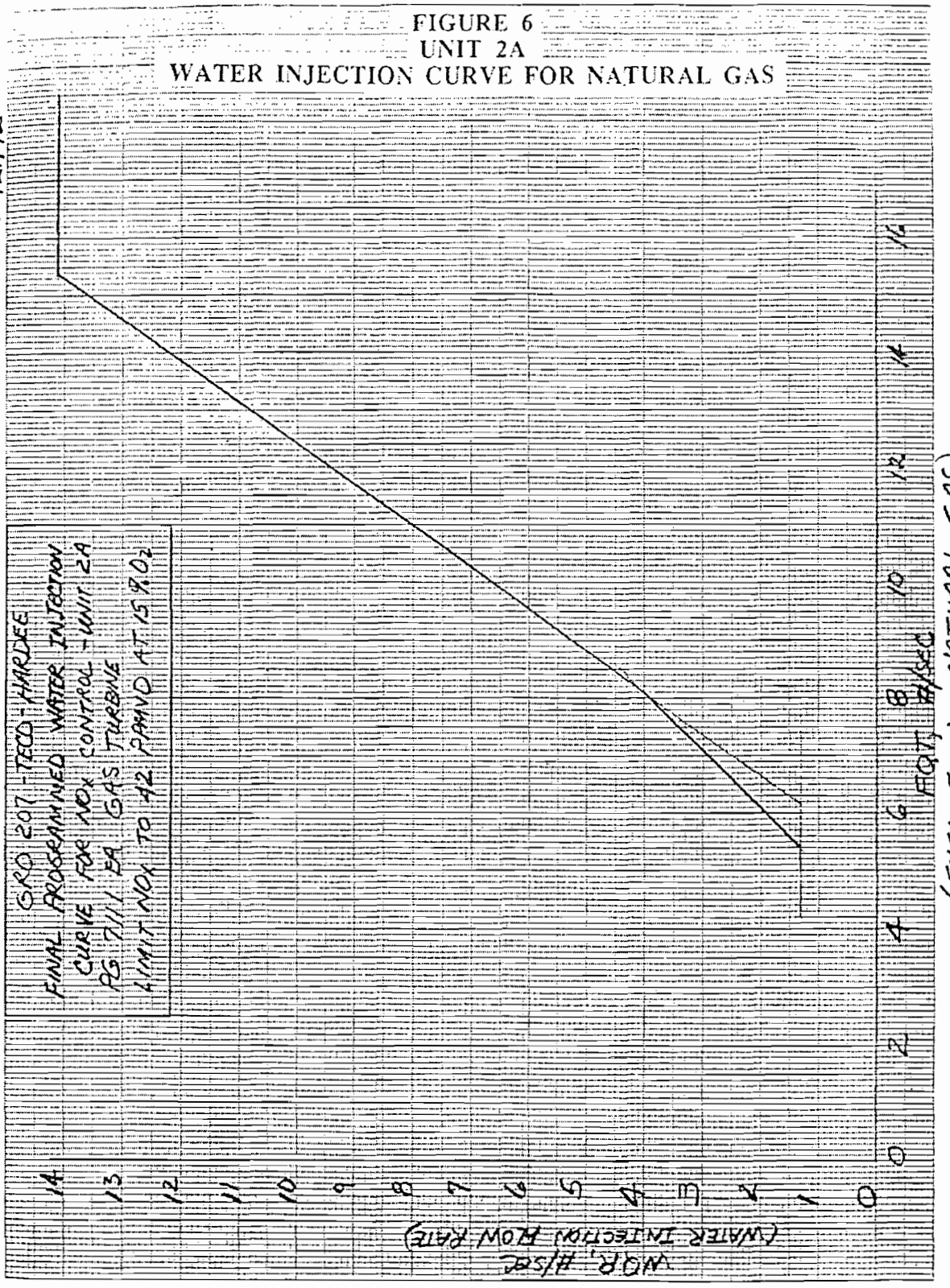


FIGURE 6
UNIT 2A
WATER INJECTION CURVE FOR NATURAL GAS



Appendix H-1: Permit History

Hardee Power Partners (A Subsidiary of Invenergy, LLC)
Hardee Power Station

PROPOSED Permit No.: 0490015-005-AV
Facility ID No.: 0490015

Permit History (for tracking purposes):

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type
All	Facility	0490015-001-AV	01/01/2000	12/31/2004	Initial
All	Facility	0490015-005-AV	01/01/2005	12/31/2009	Renewal

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

Hardee Power Partners — **PROPOSED Permit Renewal No.: 0490015-005-AV**
Hardee Power Station — **Facility ID: 0490015**

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

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

Brief Description of Emissions Units and Activities

1. Internal combustion engines in boats, aircraft and vehicles used for transportation of passengers or freight.
2. Cold storage refrigeration equipment, except for any such equipment located at a Title V source using an ozone-depleting substance regulated under 40 CFR Part 82.
3. Vacuum pumps in laboratory operations.
4. Equipment used for steam cleaning.
5. Belt or drum sanders having a total sanding surface of five square feet or less and other equipment used exclusively on wood or plastics or their products having a density of 20 pounds per cubic foot or more.
6. Equipment used exclusively for space heating, other than boilers.
7. Laboratory equipment used exclusively for chemical or physical analyses.
8. Brazing, soldering or welding equipment.
9. One or more emergency generators located within a single facility provided:
   a. None of the emergency generators is subject to the Federal Acid Rain Program; and
   b. Total fuel consumption by all such emergency generators within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
10. One or more heating units and general purpose internal combustion engines located within a single facility provided:
    a. None of the heating units or general purpose internal combustion engines is subject to the Federal Acid Rain Program; and
    b. Total fuel consumption by all such heating units and general purpose internal combustion engines within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
11. Fire and safety equipment.
12. Surface coating operations within a single facility if the total quantity of coatings containing greater than 5.0 percent VOCs, by volume, used is 6.0 gallons per day or less, averaged monthly, provided:
    a. Such operations are not subject to a volatile organic compound Reasonably Available Control Technology (RACT) requirement of Chapter 62-296, F.A.C.; and
    b. The amount of coatings used shall include any solvents and thinners used in the process including those used for cleanup.

13. Surface coating operations utilizing only coatings containing 5.0 percent or less VOCs, by volume.
14. Degreasing units using heavier-than-air vapors exclusively, except any such unit using or emitting any substance classified as a hazardous air pollutant.
15. No. 2 fuel oil truck unloading equipment
16. Oil/Water separators
17. Lube oil vents associated with rotating equipment
18. Lube oil tank vents
19. Steam cleaning equipment
20. Water treatment degasifiers/dearators
21. Architectural (equipment) maintenance painting
22. Vehicular traffic on paved roads
23. Sand blasting and abrasive grit blasting where temporary total enclosures are used to contain particulate matter emissions

Note: No exemption shall be granted to any emissions unit or activity if:

1. Such unit or activity would be subject to any unit-specific applicable requirement;
2. Such unit or activity, in combination with other units and activities proposed for exemption, would cause the facility to exceed any major source threshold(s) as defined in Rule 62-213.420(3)(c)1., F.A.C., unless it is acknowledged in the permit application that such units or activities would cause the facility to exceed such threshold(s); or
3. Such unit or activity would emit or have the potential to emit:
    a. 500 pounds per year or more of lead and lead compounds expressed as lead;
    b. 1,000 pounds per year or more of any hazardous air pollutant;
    c. 2,500 pounds per year or more of total hazardous air pollutants; or
    d. 5.0 tons per year or more of any other regulated pollutant.

[Rule 62-213.430(6), F.A.C]

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

Hardee Power Partners **PROPOSED Permit Renewal No.:** 0490015-005-AV
Hardee Power Station **Facility ID: 0490015**

Unregulated Emissions Units and 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 unit(s) and activities are neither "regulated emissions units" nor "insignificant emissions units".

E.U. ID No.	Brief Description of Emissions Unit(s) and Activities
004	One 4.4 million gallon No.2 fuel oil storage tank

INTEROFFICE MEMORANDUM

TO: Trina Vielhauer

THRU: Jim Pennington JKP

FROM: Bruce Mitchell BM

DATE: August 25, 2004

SUBJECT: Hardee Power Partners (A Subsidiary of Invenergy, LLC)
Hardee Power Station
PROPOSED Title V Air Operation Permit Renewal
Permit Project No.: 0490015-005-AV

Attached is the PROPOSED Title V Air Operation Permit Renewal, Project No. 0490015-005-AV, for the Hardee Power Partners' Hardee Power Station located 6695 County Road 663, Fort Green Springs, Hardee County. Comments were received from the Responsible Official during the comment period and the changes made are considered insignificant.

August 25, 2004, is Day 51 on the permitting clock. There is a CAM Plan included with this project.

Attachments

TLV/jkp/bm