

Facility Name: **Effingham County Power, LLC**  
 City: Rincon  
 County: Effingham  
 AIRS #: 04-13-103-00012

Application #: TV-14672  
 Date Application Received: August 13, 2003  
 Date Application Deemed Administratively Complete: October 13, 2005  
 Date of Draft Permit: January 24, 2005  
 Permit No: 4911-103-0012-V-03-0

<b>Program</b>	<b>Review Engineers</b>	<b>Review Managers</b>
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<b>Toxics</b>	N/a	N/a

## Introduction

This narrative is being provided to assist the reader in understanding the content of the attached draft Part 70 operating permit. Complex issues and unusual items are explained herein simpler terms and/or greater detail than is sometimes possible in the actual permit. This permit is being issued pursuant to: (1) Georgia Air Quality Act, O.C.G.A § 12-9-1, et seq. and (2) Georgia Rules for Air Quality Control, Chapter 391-3-1, and (3) Title V of the Clean Air Act Amendments of 1990. Section 391-3-1-.03(10) of the Georgia Rules for Air Quality Control incorporates requirements of Part 70 of Chapter I of Title 40 of the Code of Federal Regulations promulgated pursuant to the Federal Clean Air Act. The primary purpose of this permit is to consolidate and identify existing state and federal air requirements applicable to **Effingham County Power, LLC** and to provide practical methods for determining compliance with these requirements. The following narrative is designed to accompany the draft permit and is presented in the same general order as the permit. It initially describes the facility receiving the permit, the applicable requirements and their significance, and the methods for determining compliance with those applicable requirements. This narrative is intended as an adjunct for the reviewer and to provide information only. It has no legal standing. Any revisions made to the permit in response to comments received during the public participation and EPA review process will be described in an addendum to this narrative.

**I. Facility Description****A. Facility Identification**

1. Facility Name: Effingham County Power, LLC
2. Parent/Holding Company Name: Effingham County Power, LLC
3. Previous and/or Other Name(s): No previous names identified.
4. Facility Location

3440 McCall Road  
Rincon, Georgia 31326 (Effingham County)

5. Attainments or Non-attainment Area Location

The facility location is designated as an attainment area for all criteria pollutants.

6. Class I Area Impacts

The facility is not located within 100 km of a Class I area.

**B. Site Determination**

There are no other facilities which could possibly be contiguous or adjacent and under common control.

**C. Existing Permits****Table 1: List of Current Permits as Amended**

Permit Number and/or Purpose of Issuance	Date of Issuance and Date of Amendments (if any)	Comments	
		Yes	No
4911-103-0012-P-01-0	December 27, 2001	X	
4911-103-0012-P-02-0	May 2, 2002	X	

**Table 2: Comments on Specific Permits**

Permit Number	Comments
4911-103-0012-P-01-0	PSD Construction and operation permit for two combined cycle turbines.
4911-103-0012-P-02-0	Initial Acid Rain Permit

D. Process Description

1. SIC Codes(s)

**4911**

The SIC Code(s) identified above were assigned by EPD's Air Protection Branch for purposes pursuant to the Georgia Air Quality Act and related administrative purposes only and are not intended to be used for any other purpose. Assignment of SIC Codes by EPD's Air Protection Branch for these purposes does not prohibit the facility from using these or different SIC Codes for other regulatory and non-regulatory purposes.

Should the reference(s) to SIC Code(s) in any narratives or narrative addendum previously issued for the Title V permit for this facility conflict with the revised language herein, the language herein shall control; provided, however, language in previously issued narratives that does not expressly reference SIC Code(s) shall not be affected.

2. Description of Product(s)

The facility generates electricity for sale.

3. Overall Facility Process Description

The facility includes two combined-cycle combustion turbines. Each combined-cycle turbine includes heat recovery steam generator (HRSG). Each combustion turbine fire natural gas exclusively. Ancillary equipment includes one auxiliary boiler; a diesel-fired fire-water pump, a fuel pre-heater, a process cooling tower and two aqueous ammonia storage tanks.

4. Overall Process Flow Diagram (optional)

The facility provided a process flow diagram in their Title V permit application.

E. Regulatory Status

1. PSD/NSR

The facility is a major source under PSD regulations because it has the potential emissions of NO<sub>x</sub> and SO<sub>2</sub> greater than 250 tons per year (it is not one of the 28 named source categories). The facility was originally permitted in 2001 and was permitted as a major source under the PSD regulations.

## 2. Title V Major Source Status by Pollutant

Table 3: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	✓	✓		
PM <sub>10</sub>	✓	✓		
SO <sub>2</sub>	✓			✓
VOC	✓			✓
NO <sub>x</sub>	✓	✓		
CO	✓	✓		
TRS				
H <sub>2</sub> S				
Individual HAP	✓			✓
Total HAPs	✓			✓

## 3. MACT Standards

The facility is not subject to a proposed or final MACT standard.

## 4. Program Applicability

Program Code	Applicable (y/n)
Program Code 6 - PSD	Yes
Program Code 8 – Part 61 NESHAP	No
Program Code 9 - NSPS	Yes
Program Code M – Part 63 NESHAP	No
Program Code V – Title V	Yes

## **Regulatory Analysis**

### **II. Facility Wide Requirements**

- A. Emission and Operating Caps:  
Not Applicable.
- B. Applicable Rules and Regulations  
Not Applicable.
- C. Compliance Status  
Not Applicable.
- D. Operational Flexibility  
Not Applicable.
- E. Permit Conditions  
Not Applicable.

### III. Regulated Equipment Requirements

#### A. Brief Process Description

The facility includes two combined-cycle combustion turbines. Each combined-cycle turbine includes a heat recovery steam generator (HRSG). Each combustion turbine fires natural gas exclusively. Ancillary equipment includes one auxiliary boiler; a diesel-fired fire-water pump, a fuel pre-heater, a process cooling tower and two aqueous ammonia storage tanks.

#### B. Equipment List for the Process

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
CTG1	GE 7FA Combustion Turbine, 185 MW	40 CFR 60 Subpart A 40 CFR 60, Subpart GG 40 CFR 52.21 391-3-1-.02(2)(b) and (g) Acid Rain	3.3.1, 3.3.2, 3.3.4, 3.3.5, 3.3.8, 5.2.1, 5.2.2, 5.2.3, 5.2.4, 5.2.5, 5.2.6, 6.2.1, 6.2.2, 6.2.6, 6.2.7, 6.2.8, 6.2.9, 6.2.10, 6.2.11, 6.2.12	SCR1	Selective Catalytic Reduction (SCR)
CTG2	GE 7FA Combustion Turbine, 185 MW	40 CFR 60 Subpart A 40 CFR 60, Subpart GG 40 CFR 52.21 391-3-1-.02(2)(b) and (g) Acid Rain	See CTG1	SCR2	Selective Catalytic Reduction (SCR)
DWP1	Fire Water Pump Engine, 235 bhp (2.06 MMBtu/hr)	40 CFR 52.21 391-3-1-.02(2)(b) and (g)	3.2.2, 3.3.3, 5.2.2, 5.2.7, 6.2.3, 6.2.5,	N/a	N/a
FP1	Fuel Pre-heater 8.75 MMBtu/hr	40 CFR 52.21 391-3-1-.02(2)(b) and (g)	3.3.2, 3.3.6, 5.2.2, 5.2.7	N/a	N/a
AB1	Auxiliary Boiler 17 MMBtu/hr	40 CFR 60 Subpart A 40 CFR 60, Subpart Dc 40 CFR 52.21 391-3-1-.02(2)(d) and (g)	3.2.1, 3.3.2, 3.3.7, 5.2.2, 6.2.3, 6.2.4, 6.2.12	N/a	N/a
CT1	Cooling Tower 8 cells	40 CFR 52.21	3.3.9	DE1	Drift Eliminators
HRSG1	Heat Recovery Steam Generator (no duct firing)	40 CFR 52.21	N/a	N/a	N/a
HRSG2	Heat Recovery Steam Generator (no duct firing)	40 CFR 52.21	N/a	N/a	N/a
STG1	Steam Turbine Generator, 155 MW	40 CFR 52.21	N/a	N/a	N/a

#### C. Equipment & Rule Applicability

##### **Combustion Turbines CTG1 and CTG2**

The facility includes two GE Frame 7FA combined cycle combustion turbines each nominally rate at a generating capacity of 185 MW (at ISO conditions). They are capable of firing only pipeline quality natural gas. The Frame 7FA combustion turbines are capable of operating in either normal mode or with evaporative cooling.

Emissions from the Frame 7FA are controlled through the use of advanced burner technology, which controls emissions of carbon monoxide (CO), volatile organic compounds (VOC) and oxides of nitrogen (NO<sub>x</sub>) through combustion controls. The dry low NO<sub>x</sub> burner design has achieved emission levels of 9 parts per million (ppm) on a dry volume basis. Their emission limitation is 3 ppm corrected to 15% oxygen, which can be achieved by using the selective catalytic reduction system.

Each combustion turbine is subject to the requirements of 40 CFR 60, Subpart GG - "Standard of Performance for Stationary Gas Turbines" because each has a heat input at peak load equal to or greater than 10.7 giga-joules per hour [10.14 MMBtu/hr], based on the lower heating value of the fuel fired; and because the turbines were constructed after October 3, 1977. The NSPS General Provisions [40 CFR 60, Subpart A] also apply to each turbine. The NSPS limits the NO<sub>x</sub> emissions from on an equation based on the heat input. The most stringent NO<sub>x</sub> emission rate is established by 40 CFR 52.21 (a.k.a. PSD), which subsumes the requirement of NSPS GG.

The Acid Rain Program regulates sulfur dioxide emissions from the turbines. Effingham County Power must obtain, in the open market, the number of SO<sub>2</sub> allowances that correspond to their annual SO<sub>2</sub> emissions.

Visible emissions from each combustion turbine stack are regulated by 40 CFR 52.21 and Georgia Rule 391-3-1-.02(2)(b). The requirements of 40 CFR 52.21 subsume the requirements of Georgia Rule (b). The BACT limit for visible emissions is ten (10) percent.

Particulate matter emissions from each combustion turbine are regulated by 40 CFR 52.21 and Georgia Rule 391-3-1-.02(2)(d). The most stringent emission limit is specified by PSD. The BACT PM/PM<sub>10</sub> emission limit for each stack is 21.6 pound per hour.

Carbon monoxide emissions from each combustion turbine are regulated by 40 CFR 52.21. The BACT CO emission limit for each stack is 9.0 ppmvd corrected to 15% oxygen. Another BACT CO emission limitation for each stack is 3.0 ppmvd, corrected to 15% oxygen for more than 30% of the operating time excluding hours during startup, shutdown, or malfunction during any calendar quarter. The turbines are also limited to 144.5 tons of CO during any twelve consecutive months as required by their PSD permit.

Nitrogen Oxide emissions from each combustion turbine are regulated by 40 CFR 52.21. The BACT NO<sub>x</sub> emission limit for each stack is 3.0 ppmvd corrected to 15% oxygen. NO<sub>x</sub> is also limited to 109 tons per any 12 consecutive months and includes period of startup and shutdown.

Both combustion turbines are limited on the amount of time for cold startups, warm startups, hot startups or unit shutdowns, as determined by their PSD permit. This is determined by what state the turbine currently is.

Both combustion turbines are limited to burn only natural gas as determined by their PSD permit. This requirement subsumes NSPS GG and Georgia Rule (g) limit for sulfur content.

**Auxiliary Boiler**

The Auxiliary Boiler (Source Code AB1) is subject to Georgia Rule (d) for opacity and particulate matter emissions and Rule (g) for sulfur limitations in the fuel burned. This emission unit is also subject to 40 CFR 60, Subpart Dc, "NSPS for Small Industrial-Commercial-Institutional Steam Generating Units."

PM/PM<sub>10</sub> emissions from the boiler are regulated by Georgia Rule 391-3-1-.02(2)(d). Georgia Rule (d) specifies an emission limit of approximately 0.38 pound per million Btu heat input. Since the boiler can only burn natural gas, which has low ash content, no monitoring is required from the boiler.

NO<sub>x</sub> emissions from the boiler are regulated by 40 CFR 52.21 [PSD-BACT], which specifies an emission limit of 0.098 lb/MMBtu.

CO emissions from the boiler are regulated by 40 CFR 52.21 [PSD-BACT], which specifies an emission limit of 0.082 pound per million Btu heat input.

Sulfur dioxide emissions from the boiler are regulated under Georgia Rule 391-3-1-.02(2)(g)2 which specifies for all fuel burning sources less than 100 MMBtu/hr, that the fuel burned cannot contain more than 2.5 percent sulfur, by weight. The boiler is required to only burn natural gas, which has minimal sulfur content so sulfur emissions from the fuel source are expected to be minimal. This requirement subsumes NSPS Dc and Georgia Rule (g) limit for sulfur content.

The boiler is limited to 2,500 hours per year as determined by the PSD determination.

**Engines and Other**

Diesel Fire Water Pump Engine (Source Code DWP1) and Fuel Pre-Heater (Source Code FP1) are subject to 40 CFR 52.21(j) for NO<sub>x</sub>, CO, PM/PM<sub>10</sub>, SO<sub>2</sub>, and visible emissions; and to Georgia Rules 391-3-1-.02(2)(b) and (g) for visible emissions and fuel sulfur content. The PSD permit establishes a work practice standard for source code DWP1 of 500 hours on fuel oil combustion during any twelve consecutive months for purposes of the requirements of PSD for NO<sub>x</sub>, CO, PM/PM<sub>10</sub>, SO<sub>2</sub>, and visible emissions. In addition, the PSD permit limits the fuel oil sulfur content to 0.05 weight percent. Georgia Rule (b) limits the visible emissions to no more than forty (40) percent. Georgia Rule (g)2 limits the fuel sulfur content to no more than 2.5 weight percent. The PSD fuel oil sulfur content limit subsumes Georgia Rule (g)2. Therefore, fuel oil sulfur content and opacity will be expected at all times.

The PSD permit establishes a work practice standard for source code FP1 of burning only natural gas and limits NO<sub>x</sub> and CO emission to 0.05 lb/MMBtu and 0.082 lb/MMBtu, respectively.

The 8-cell Cooling Tower (Source Code CT1), Heat Recovery Steam Generator (no duct firing) (Source Code HRSG1 and HRSG2), and the Steam Turbine Generator (Source Code STG1) are only subject to the requirements of 40 CFR 52.21. Source Code CT1 requirements were to install drift Eliminators (Source Code DE1). There are no other requirements from this set of emission units.

D. Compliance Status

There are no compliance related issues for the combustion turbines

E. Operational Flexibility

Not applicable.

F. Permit Conditions

Conditions 3.2.1 through 3.2.2 and 3.3.2 through 3.3.8 are all PSD requirements and are discussed in further below.

Condition 3.2.1 limits the Auxiliary Boiler (Source Code AB1) to less than 2,500 hours during any twelve consecutive months.

Condition 3.2.2 limits the Diesel Fire Water Pump Engine (Source Code DWP1) to less than 500 hours during any twelve consecutive months.

Condition 3.3.1 specifies that the General Provisions of 40 CFR Part 60 Subpart A are applicable for the turbines and that 40 CFR Part 60 Subpart GG also applies to the turbines.

Condition 3.3.2 specifies the PSD requirement that the turbines, the auxiliary boiler, and the fuel pre-heater only fire natural gas.

Condition 3.3.3 specifies the maximum fuel sulfur content limit (0.05%) for fuel burned in the Diesel Fire Water Pump Engine (Source Code DWP1).

Condition 3.3.4 specifies the PSD/BACT emission limits for the turbines.

Condition 3.3.5 specifies the rolling PSD NO<sub>x</sub> and CO emissions limit (in tpy) for the turbines.

Condition 3.3.6 specifies the PSD/BACT emission limits for the fuel pre-heater.

Condition 3.3.7 specifies the PSD/BACT emission limits for the auxiliary boiler.

Condition 3.3.8 provides the definitions of startup and shutdown as they relate to the combustion turbines.

**IV. Testing Requirements (with Associated Record Keeping and Reporting)****A. General Testing Requirements**

The permit includes a requirement that the Permittee conduct performance testing on any specified emission unit when directed by the Division. Additionally, a written notification of any performance test(s) is required 30 days prior to the date of the test(s) and a test plan is required to be submitted with the test notification. Test methods and procedures for determining compliance with applicable emission limitations are listed and test results are required to be submitted to the Division within 60 days of completion of the testing.

**B. Specific Testing Requirements**

The facility is required to test for CO on the Auxiliary Boiler (Source Code AB1). No previous test was done and there is no data to confirm compliance with its PSD CO limit.

## V. Monitoring Requirements (with Associated Record Keeping and Reporting)

### A. General Monitoring Requirements

Condition 5.1.1 requires that all continuous monitoring systems required by the Division be operated continuously except during monitoring system breakdowns and repairs. Monitoring system response during quality assurance activities is required to be measured and recorded. Maintenance or repair is required to be conducted in an expeditious manner.

### B. Specific Monitoring Requirements

Each combined combustion turbine stack are subject to the requirements of 40 CFR 52.21 [PSD] for NO<sub>x</sub>, CO, PM/PM<sub>10</sub>, SO<sub>2</sub> emissions and visible emissions; and 40 CFR 60 Subpart GG [NSPS GG] for NO<sub>x</sub> and SO<sub>2</sub> emissions. The PSD requirements subsume the requirements for visible emissions specified in Georgia Rule 391-3-1-.02(b). The NO<sub>x</sub> emissions and fuel sulfur content requirements in NSPS GG. Verification of the requirements for SO<sub>2</sub> emissions (i.e., fuel sulfur content) is via record keeping which is discussed in Section VI of this narrative.

To reasonably assure compliance with the requirements of 40 CFR 52.21 for NO<sub>x</sub> emissions, the Continuous Emissions Monitoring Systems (CEMS), required by the Acid Rain regulations, are used to monitor NO<sub>x</sub> emissions. The NO<sub>x</sub> CEMS provides an indicator of compliance regarding each combustion turbine's compliance status on a continuous basis following the initial tests. The values reported by the NO<sub>x</sub> CEMS are used to assess the existence of an exceedance and an exceedance is defined as any three-hour average NO<sub>x</sub> emission rate which exceeds 3.0 ppmvd, corrected to 15% oxygen.

Verification of compliance with the rolling annual NO<sub>x</sub> emission limit per combustion turbine is discussed in Part VI of this narrative. Verification of compliance with the NO<sub>x</sub> emission limit is discussed in Part VI of this narrative.

Carbon monoxide emissions from each combustion turbine stack are regulated by 40 CFR 52.21. In this case, 40 CFR 52.21 imposes a short term CO BACT emissions limit and a BACT work practice standard.

The short term CO BACT emission limits apply during startup and shutdown. Startup means the commencement of operation of any source, and in this case, lasts until the BACT technology (i.e., low NO<sub>x</sub> combustor) is engaged. EPD believes there is a likelihood of violating the short-term CO BACT emission limits during startup and shutdown. EPD has required the installation and operating of CO Continuous Emissions Monitoring Systems (CEMS) in recent PSD combustion turbine plant air quality permits in order to verify compliance with the short term CO BACT emission limit during all periods of operation. EPD believes that, in this case, periodic monitoring for the short term CO BACT emission limit should be the installation and operation of CO CEMS.

The requirement to install and operate a CO CEMS on the turbine stacks is specified by Condition 5.2.1.b. The CO CEMS quality assurance and minimum data requirements are specified in Condition Nos. 5.2.6 and 5.2.7. An exceedance for purposes of Title V includes any

3-hour rolling average CO emissions rate that exceeds 9.0 ppmvd corrected to 15% oxygen. In addition to the 9.0 ppmvd limitation, there is also a 3.0 ppmvd for 30% of the operating time. Verification will be done through hours of operation and their CO CEMS.

Particulate matter and visible emissions from each combustion turbine stack are regulated by 40 CFR 52.21. Initial compliance with the short term PM/PM<sub>10</sub> and visible emission limits were verified through initial performance tests. Natural gas is a clean burning fuel and the likelihood of violating the established BACT limits is minimal. Thus, no additional periodic monitoring is prescribed for PM/PM<sub>10</sub> and visible emissions.

The Auxiliary Boiler (AB1) is subject to 40 CFR 52.21 for NO<sub>x</sub>, CO, SO<sub>2</sub>, PM, and PM<sub>10</sub>; NSPS Dc; and Georgia Rules 391-3-1-.02(2)(d) and (g) for PM, visible emissions, and fuel sulfur content. PSD (40 CFR 52.21) specifies the most stringent standard for each air pollutant noted above.

For SO<sub>2</sub> (sulfur content), PM/PM<sub>10</sub>, and visible emissions, the use of natural gas, which is a clean burning fuel and contains negligible amounts of sulfur, gives EPD a reasonable assurance of compliance. The PSD permit requires the Permittee to monitor the cumulative total hours of operation, during all periods of operation, for the boiler. Verification of compliance with this operational limit is discussed in Section VI of this narrative.

The Auxiliary Boiler was tested for NO<sub>x</sub> on March 13, 2003. The test showed the source was in compliance with its NO<sub>x</sub> limit by approximately 50%. Therefore, the likelihood of violation of this limit is minimal and no periodic monitoring is required. The permit requires testing for CO since there is no data to confirm compliance with its PSD CO limit. Periodic monitoring for CO may be added following review of the test results.

The Fire Water Pump Engine (Source Code DWP1) is subject to 40 CFR 52.21 for NO<sub>x</sub>, CO, SO<sub>2</sub>, PM, PM<sub>10</sub>, visible emissions; and Georgia Rules 391-3-1-.02(2)(g) and (b) for fuel sulfur content and for visible emissions. PSD (40 CFR 52.21) specifies the most stringent standard for fuel sulfur content (SO<sub>2</sub> emissions) and for visible emissions. PSD does not specify emission standards or work practice standards for NO<sub>x</sub>, CO, PM, and PM<sub>10</sub> emissions. Very low sulfur distillate fuel oil is a clean burning fuel and the likelihood of violating the established BACT limits is minimal. Thus no additional periodic monitoring is prescribed for PM/PM<sub>10</sub> and visible emissions. Verification of the requirements for SO<sub>2</sub> emissions (i.e., fuel sulfur content) is via record keeping which is discussed in Section VI of this narrative.

The Fuel Pre-heater (Source Code FP1) is subject to PSD limits for NO<sub>x</sub>, CO, and fuel sulfur content; and Georgia Rules 391-3-1-.02(2)(b) and (g) for visible emissions and fuel sulfur content. PSD (40 CFR 52.21) specifies the most stringent standard for fuel sulfur content. A performance test for CO and NO<sub>x</sub> emissions from the boiler have been performed. The tested CO and NO<sub>x</sub> emission rate were approximately 93 percent and 85 percent of the allowable emissions limit, respectively; EPD believes that additional periodic monitoring should be imposed to provide for a reasonable assurance of compliance with the allowable CO and NO<sub>x</sub> emissions limit. Periodic monitoring shall consist of requiring the use of CTM-30 (a portable CO/NO<sub>x</sub> analyzer) on a monthly basis until results show 2 consecutive measurements of less than **0.082 lb/MMBtu** (for CO) and **0.05 lb/MMBtu** (for NO<sub>x</sub>) at which time the frequency is reduced to

quarterly. Any excursion of the applicable emission standard will trigger daily (per operating day) monitoring until the problem is corrected. In lieu of CTM-30, EPA reference method 10 (for CO) and 7E (NOx) may be used.

The Fuel Pre-heater only fires very low sulfur fuel oil (0.05%). Thus the likelihood of a violation of Rule (b) or (g) is minimal and no periodic monitoring is required.

## VI. Other Record Keeping and Reporting Requirements

### A. General Record Keeping and Reporting Requirements

The Permit contains general requirements for the maintenance of all records for a period of five years following the date of entry and requires the prompt reporting of all information related to deviations from the applicable equipment. Records, including identification of any excess emissions, exceedances, or excursions from the applicable monitoring triggers, the cause of such occurrence, and the corrective action taken, are required to be kept by the Permittee and reporting is required on a semiannual basis.

### B. Specific Record Keeping and Reporting Requirements

Verification of compliance with the each combustion turbine rolling annual total NO<sub>x</sub> emission rate is determined using the NO<sub>x</sub> CEMS data to compute the NO<sub>x</sub> mass emission rate. The Permittee is required to maintain monthly records, which specify the twelve consecutive month total NO<sub>x</sub> emissions (in tons) from each combined combustion turbine. Failure to maintain NO<sub>x</sub> emissions from each combustion turbine in excess of 109 tons during any twelve consecutive months must be reported as an exceedance.

Records are maintained for the time attributed to the startup and shutdown of each combustion turbine to verify compliance with Condition 3.3.8.

PSD sets the maximum sulfur content for diesel fuel use in the fire water pump engine at 0.05 weight percent. The applicant shall verify and document that each shipment of diesel fuel oil received for combustion in the diesel fired water pump complies with this fuel sulfur limit by fuel oil receipts and/or documented analyses.

The boiler (Source Code AB1) is subject to a PSD operational limit of 2,500 hour during any twelve consecutive months. The ancillary engine (DWP1) is subject to a PSD operational limit of 500 hours during any twelve consecutive months. The Permittee is required to maintain records specifying the total operating hours for these pieces of equipment for each twelve consecutive month period ending with each calendar month. Failure to maintain the operational time of the boiler below 2,500 hours during any twelve consecutive months must be reported as an exceedance. Failure to maintain the operational time of each the ancillary IC engine (DWP1) below 500 hours during any twelve consecutive months must also be reported as an exceedance.

The facility must also monitor the amount of natural gas in the fuel pre-heater and both turbines as described in their PSD permit. This is required to calculate the NO<sub>x</sub> emissions from these emission points.

Verification of compliance with the each combustion turbine rolling annual total CO emission rate is determined using the CO CEMS data to compute the CO mass emission rate. The Permittee is required to maintain monthly records, which specify the twelve consecutive month total CO emissions (in tons) from each combined combustion turbine. Failure to maintain CO emissions from each combustion turbine in excess of 144.5 tons during any twelve consecutive months must be reported as an exceedance.

CO emissions are calculated in Condition 6.2.10 using the records recorded in Condition 6.2.9. The twelve-month rolling total of CO emissions is calculated in Condition 6.2.11.

Condition 6.1.4 outlines the semiannual reporting requirements. Condition 6.2.12 specifies additional parameters, which must be included in these semiannual reports.

**VII. Specific Requirements****A. Operational Flexibility**

This permit includes the standard conditions allowing section 502(b)(10) changes and off-permit changes. Additional operational flexibility provisions do not need to be incorporated into this Title V permit as their permit already provides sufficient flexibility for the facility. The applicant did not include any alternative operating scenarios in their Title V permit application.

**B. Alternative Requirements**

Not Applicable.

**C. Insignificant Activities**

refer to §4.10 of the Title V permit application

**D. Temporary Sources**

Not Applicable.

**E. Short-Term Activities**

Not Applicable.

**F. Compliance Schedule/Progress Reports**

Not Applicable.

**G. Emissions Trading**

Not Applicable.

**H. Acid Rain Requirements**

This facility is subject to requirements in Title IV of the Clean Air Act. They are subject to 40 CFR 72 (permits), 73 (sulfur dioxide), and 75 (monitoring). They are not subject to the nitrogen oxide provisions (40 CFR 76) of the Acid Rain regulations. 40 CFR 76 only applies to affected units that burn coal.

40 CFR 72.50(a)(1) allows a complete Phase II Permit Application to be attached to the Title V Permit as part of the Permit. Effingham County's Phase II Permit Application is attached to the Title V Permit as part of the Permit to ensure that all Acid Rain applicable requirements are incorporated into the Title V Permit.

I. Prevention of Accidental Releases

Not Applicable.

J. Stratospheric Ozone Protection Requirements

Not Applicable.

K. Pollution Prevention

Not Applicable.

L. Specific Conditions

Not Applicable.

**VIII. General Provisions**

Generic provisions have been included in this permit to address the requirements in 40 CFR Part 70 that apply to all Title V sources, and the requirements in Chapter 391-3-1 of the Georgia Rules for Air Quality Control that apply to all stationary sources of air pollution.

## Addendum to Narrative

EPD issued draft Title V Permit No. 4911-103-0012-V-03-0 for the Effingham County Power, LLC in Rincon, Georgia on January 24, 2005. The public notice for this permit was published in the Effingham Herald on February 15, 2005. The 30-day public review started on February 15, 2005 and ended on March 17, 2005.

Comments were received by the Division from The Sierra Club on March 9, 2005 and from Effingham Power Company, LLC on March 17, 2005. Each comment is printed below, followed by a discussion of the comment and any changes made to the permit as a result

### Comments Submitted By Sierra Club

- **The permit should allow all credible evidence unambiguously.** The permit should contain a condition which makes it clear that all credible evidence is admissible. Condition 4.1.3 can be said to allow all credible evidence but this is indirectly. Condition 8.26.1, titled "Use of Any Credible Evidence of Information", represents a step in the right direction but it is very difficult to understand and therefore unacceptable. We suggest the following language:

"Notwithstanding the conditions of this permit that state specific methods that may be used to assess compliance or noncompliance with applicable requirements, other credible evidence may be used to demonstrate compliance or noncompliance."

This language was suggested by the US EPA in a letter from Stephen Rothblatt, Acting Director Air and Radiation Division, to Paul Deubenetzky, Indiana Department of Environmental Management, dated July 28, 1998.

Also, the citation to the legal authority for this provision should be 62 FR 8314 (Feb. 24, 1997) and 40 CFR 51.12, 51.212, 52.30, 60.11, and 61.12, in addition to 391-3-1-.02(3)(a).

**Response:** EPD has included Condition 8.26.1 in this permit to address this issue and does not believe further revision to the Title V template is necessary for clarification. As such, the permit is not changed based on this comment.

- **The full report of malfunctions should be submitted within seven days.** Condition 6.1.2 does not represent 391-3-1-.02(6)(b)1(iv) accurately. It can therefore be interpreted as requiring two reports: the first to inform the Division of a malfunction within 7 days of the occurrence; the second to discuss probable causes and corrective actions, to be submitted any time after the occurrence of the malfunction at the facility's discretion. There is no deadline for the facility to submit the latter report.

The text of this condition must match the corrected version in the Cemex permit number 3241-153-0003-V-03-0. The template must be updated as well.

- 6.1.2 In addition to any other reporting requirements of this Permit, the Permittee shall report to the Division in writing, within seven (7) days, any deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning, or emissions control equipment for a period of four hours or more which results in excessive emissions.

The Permittee shall submit a written report that shall contain the probable cause of the deviation(s), duration of the deviation(s), and any corrective actions or preventive measures taken.

[391-3-1-.02(6)(b)1(iv), 391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(3)(iii)(B)]

**Response:** EPD agrees that condition 6.1.2 could be misconstrued. As was done in the Cemex permit that Sierra Club references, the final permit contains the reworded condition 6.1.2 that clearly states one single report is required to be submitted within seven days by the Permittee.

- **Condition 6.1.4 must not rely on discretionary decisions.** Section (c) under 6.1.4 seems to rely on off-permit definitions determined by the Director:

“The magnitude of all excess emissions, exceedances and excursions computed in accordance with the applicable definitions as determined by the Director, and any conversion factors used, and the date and time of the commencement and completion of each time period of occurrence.”

According to this paragraph, the Director is granted sole discretion in determining the applicable definitions for non-compliance. We suggest ‘in accordance with the applicable definitions in this permit or, when unspecified as determined by the Director’.

**Response:** Exceedances, excursions and excesses each have specific and quantifiable units of measure. The Director is empowered to uphold State Law by issuing and enforcing permits whose conditions have been written in accordance with those laws and which stipulate specific compliance terms and emissions limits in accordance with those Rules. These events are not subject to random interpretation, and he or she must uphold the permit requirements. As such, the permit is not changed based on this comment.

- **Critical compliance records must be submitted to the Division.** Title V is supposed to make it possible for the public to determine the degree to which facilities comply with the air pollution laws and regulations. Hence the Division should aim to provide open access at least to critical compliance records.

This applies especially to the following records which the Effingham County Power is required to maintain.

- Quarterly accuracy assessments of the CO CEMS drift tests and Out-of Control Periods for the CO CEMS during each calendar quarter (Condition 5.2.5).
- Periods during each calendar month for which CO emissions data have not been obtained for 75 percent of the turbine operating hours during the month, including reasons for not obtaining sufficient data and a description of corrective actions taken (Condition 5.2.6).
- The startup and shutdown of each combustion turbine (CTG1 and CTG2): the time attributed to the startup, type of startup (cold, warm or hot start) and the time attributed to shutdown (Condition 6.1). The Permittee is required to report irregular startup and shutdown events, but the frequency and type of startup and shutdown events are no less pertinent to air quality.

**Response:** At any such time that the Public requests records, with the exception of records identified in chapter 50-18-72 of the Georgia Code, the Division is required by law to obtain it from the Company and the Company must provide it under the (Georgia Open Records Act GORA). The Division works hard to insure that it meets the needs of any citizen or public group requesting such information. The permit is not changed based on this comment.

- **Section 112 (r) problem.** Condition 7.10.1 is to apply “when and if” the requirements of 40 CFR Part 68 become applicable. The permit must state explicitly whether the requirements are applicable at the time the permit is issued. If they are applicable, then we will conclude that, to be in compliance, the Permittee is obliged to submit a valid Risk Management Plan.

**Response:** The requirements of 40 CFR Part 68 are triggered under certain situations and may not always apply, therefore, the template language is reflective. As such, the permit is not changed based on this comment.

- **Boiler references must be specific.** Condition 5.2.7.a requires monitoring CO and NO<sub>x</sub> emissions “from each boiler (Source Code FP1).” Hence, this condition only applies to one boiler- the fuel pre-heater FP1. Subsequent references to “each boiler” or just “boiler” – in Condition 5.2.7 b and Condition 5.2.7.c – do not specify any source code and it is therefore not clear whether they apply to other boilers as well or not.

Condition 5.2.7.a should only specify FP1, not ‘each boiler’, and the remaining conditions should specify the source code(s) of the equipment to which they apply.

**Response:** EPD agrees this sentence is inaccurate as written. Condition 5.2.7 has been changed to include the corrected source codes (the boiler should actually be the fuel preheater) and to clarify the intent of these sentences.

- **The auxiliary boiler must be monitored for nitrogen oxide emissions.** The auxiliary boiler (AB1) may discharge emissions with no more than 0.098 lb/MMBtu, as specified in Condition 3.3.7.a. The draft permit does not require any monitoring for compliance with this condition since, as explained in the Narrative, a test for NO<sub>x</sub> on March 13, 2003 “showed the source was in compliance with its NO<sub>x</sub> limit by approximately 50%”, and “the likelihood of violation of the limit is minimal”.

The Permittee should be required to repeat the NO<sub>x</sub> emissions test at least on an annual basis, since there is no certainty that NO<sub>x</sub> emissions will not increase over time.

**Response:** A review of the initial testing data on boiler (AB1) revealed that even operating at maximum capacity (17 MMBtu/hr) its NO<sub>x</sub> emissions were at approximately 50% of the permitted limit. Therefore, the Division does not deem any additional monitoring or record keeping necessary for NO<sub>x</sub> emissions. No changes to the permit are warranted.

- **Condition 8.14.4 reference must be corrected.** Condition 3.3.5.c refers to “Paragraphs (i) and (ii) of Condition 8.14.4”. The reference must be corrected to “... of Condition 8.14.4.a”.

**Response:** EPD agrees and this condition is changed based on this comment.

- **Carbon monoxide monitoring must be continuous.** The Permittee is required to “install, calibrate, maintain, and operate a system to continuously monitor and record” carbon monoxide emissions from each combustion turbine (Condition 5.2.1.b). But then Condition 5.2.6 relaxes the requirement for continuous monitoring by requiring CO emission data from just 75 percent of operating hours. We can find no justification for this relaxation. CO monitoring must be active at all times, except for periods of regular maintenance and repair.

**Response:** EPD does not agree that Condition 5.2.6 relaxes monitoring requirements, but rather it acknowledges that at some periods, such as regular maintenance and repair, data collection is sometimes interrupted. Permit Condition 5.2.6 allows 75% data collection (a minimum) to be assumed representative of the overall operational data for that month. During inspections continuous monitors are checked to be sure they are working properly. The permit is not changed based on this comment.

- **The narrative must be corrected.** The header of Section III.C in the Narrative is “Combustion Turbines T1, T2, T3, T4, and T5”. According to Section III.B, the facility possesses only two combustion turbines, labeled CTG1 and CTG2. The draft permit as well does not refer to any other combustion turbines.

**Response:** EPD agrees and the narrative has been corrected to fix this typographical mistake.

- **The narrative must be corrected.** Under the header “Auxiliary Boiler” in Section III.C, the paragraph which begins with the words “Sulfur dioxide emissions” is somewhat garbled. It contains the following senseless sentence: “Again, since the boiler is required to only burn natural gas, which has minimal sulfur content.”

**Response:** EPD agrees, and the narrative has been changed to be clearer.

#### Comments Submitted By Effingham County Power, LLC

- **Section 5.2.7** – Request the reference to the natural gas fuel preheater (FP1) be changed from “boiler” to “preheater”.

**Response:** EPD agrees this sentence as written is inaccurate. Condition 5.2.7 has been changed to include the corrected source codes (the boiler should actually be the fuel preheater) and to clarify the intent of these sentences.

- **Section 5.2.7(c) – Comment #1:** Request that the frequency of emissions testing for the natural gas fuel preheater be reduced to twice a year (biannually) for preheater operation greater than 336 hours for each 6 month calendar period. The basis for decreased testing is due to the inherent operational stability of the fuel preheater, the consistency of the fuel (natural gas), and the component simplicity of the preheat system. It is our belief that there is minimal benefit in quarterly monitoring of the fuel preheater based on the above-stated facts, and is a significant burden to the facility.

**Response:** EPD agrees to a modified sampling schedule as discussed in response to the next question.

- **Section 5.2.7(c) – Comment #2:** Request that the emission testing requirement for the natural gas fuel preheater (FP1) be amended to allow a lower frequency of emissions testing based on the results of the initial, and subsequent emissions tests. Specifically, we request that emissions testing of the fuel preheater be required annually if the unit is equal to or less than 60% of the emission limit for NO<sub>x</sub> and CO respectively. Additionally, if the unit is within 60% of the emission limits for two consecutive annual performance tests, we request that emissions testing for the natural gas preheater be conducted once every two years.

**Response:** EPD agrees to relax the emissions monitoring requirement to annual sampling after two quarterly sampling test results show emissions are fifty percent or less of the emissions limitations listed in Condition 5.2.7.d. Annual sampling shall have approximately twelve-month intervals not to exceed thirteen months between tests. If the test results from the previous annual test is fifty percent or less of the limitation in Condition 5.2.7.d. then Effingham County Power, LLC may write to EPD and request testing be deferred for a period no greater than twelve months from the required annual test date. If the limits exceed the requirements of fifty percent or less of the limitation in Condition 5.2.7.d. then quarterly testing will be required. This modification is added to the permit conditions.

- **Section 5.2.7(d) –** Request that the definition of “one unit operating day” be increased from 30 minutes to 60 minutes. This would be consistent with the allowable shutdown duration of the CTs stated in the draft permit (see Section 3.3.8(d) and eliminate the need to conduct an additional emission measurement on the fuel preheater prior to the unit being shutdown and repairs being made.

**Response:** EPD agrees and Section 5.7.2(e) is changed to increase the definition of “one unit operating day” to sixty minutes (for the purpose of fuel preheater (FP1) measurement) based on this comment.

#### **New/Modified Permit Conditions and Narrative Modifications with changes italicized and underlined.**

6.1.2 In addition to any other reporting requirements of this Permit, the Permittee shall report to the Division in writing, within seven (7) days, any deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning, or emissions control equipment for a period of four hours or more which results in excessive emissions. *This written report* that shall contain the probable cause of the deviation(s), duration of the deviation(s), and any corrective actions or preventive measures taken.

[391-3-1-.02(6)(b)1(iv), 391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(3)(iii)(B)]

5.2.7 The Permittee shall monitor the emissions of Carbon Monoxide (CO) and Nitrogen Oxides (NO<sub>x</sub>) from the *Fuel Preheater (Source Code FP1)*. The monitoring shall be conducted according to the following plan: [391-3-1-.02(6)(b)1, 40 CFR 70.6(a)(3)(i)]

- a. Measurements of carbon monoxide concentrations, nitrogen oxides concentrations, and oxygen concentration shall be conducted using the procedures of Gas Research Institute Method GRI-96/0008, EPA/EMC Conditional Test Method (CTM-30) *Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers and Process Heaters Using Portable Analyzers*. In lieu of CTM-30, Method 10, Method 7E, and Method 3A may be used to determine the concentrations of carbon monoxide, nitrogen oxides, and oxygen, respectively.
- b. Within 180 days of the date of issuance of this permit, the Permittee shall measure the carbon monoxide, nitrogen oxides, and oxygen emissions from *Fuel Preheater (FPI)*. The initial and subsequent measurement periods shall consist of one (1) test run thirty (30) minutes in duration. Carbon Monoxide and Nitrogen oxides emissions rate (pounds per million Btu) for the Fuel Pre-Heater shall be determined using the following equation;

$$E = K C_d F_d \frac{20.9}{20.9 - O_2}$$

where:

E = Mass emissions of nitrogen oxides (lb/mmBtu)

K = Conversion factor for nitrogen oxides =  $1.194 \times 10^{-7}$  ([lb/scf]/ppm)

K = Conversion factor for carbon monoxide =  $7.263 \times 10^{-8}$  ([lb/scf]/ppm)

C<sub>d</sub> = Concentration of nitrogen oxides (ppm by volume, dry basis)

F<sub>d</sub> = F-factor for natural gas (dscf/MMBTU)

O<sub>2</sub> = Exhaust Gas Oxygen Concentration (percent by volume, dry basis)

- c. Following the initial measurement, the Permittee shall conduct a measurement during any calendar quarter that the *fuel preheater (FPI)* operates for 168 hours until the emission limits in 5.2.7.d. If, after two quarterly sampling events, the measurement from the (FPI) are 50% or less of the limitation in condition 5.2.7.d, annual measurements may be performed. Annual measurements shall be conducted at approximately 12 month intervals not to exceed thirteen months between measurements. The Permittee may, if measurement results from the previous annual measurement is 50% or less of the limitation in condition 5.2.7.d, request that measuring be deferred for a period no greater than twelve months from the required annual test date. Such request shall be in written form and received by the Division at least thirty days prior to the scheduled test. If the test results are greater than 50% of the limits set forth in 5.2.7.d, quarterly testing requirements shall be resumed.
- d. Following any measurement (including the initial measurement) that is greater than 0.05 lb/MMBtu (NO<sub>x</sub> limit) or 0.082 lb/MMBtu (CO limit), the Permittee shall take corrective action in the most expedient manner possible and conduct a new measurement within one unit operating day.

- e. A unit operating day, *for the purpose of this condition*, shall be defined as any day that the unit is operated for more than 60 minutes between 12:00 midnight and the following midnight.
  - f. A record of carbon monoxide and nitrogen oxides monitoring shall be kept in a form suitable for inspection or submittal for a period of five (5) years. The records shall at a minimum contain the cause and corrective action for all excursions, the date of each measurement, and the concentration of nitrogen oxides.
- 3.3.5 The Permittee shall not discharge, or cause the discharge, into the atmosphere, from any combustion turbine, CTG1 or CTG2:
- a. NOx emissions, including emissions occurring during startup and shutdown, in excess of 109.0 tons during any twelve consecutive months.  
[40 CFR 52.21(j)]
  - b. CO emissions, including emissions occurring during startup and shutdown, in excess of 144.5 tons during any twelve consecutive months.  
[40 CFR 52.21(j)]
  - c. Paragraphs (i) and (ii) of *Condition 8.14.4(a)*. do not apply to Condition 3.3.5a and b regarding startup and shutdown emissions. Emissions during startup and shutdown shall be counted toward the mass emission limits in this permit condition.  
[391-3-1-.02(2)(a)7(iii)]

## Revisions to the Narrative

Section III.C Title changed to: **Combustion Turbines CTG1 and CTG2**

**Section III.C Auxiliary Boiler** (5<sup>th</sup> Paragraph from top modified as follows):

Sulfur dioxide emissions from the boiler are regulated under Georgia Rule 391-3-1-.02(2)(g)2 *which specifies for all fuel burning sources less than 100 MMBtu/hr, that the fuel burned cannot contain more than 2.5 percent sulfur, by weight.* The boiler is required to only burn natural gas, which has minimal sulfur content so sulfur emissions from the fuel source are expected to be minimal. This requirement subsumes NSPS Dc and Georgia Rule (g) limit for sulfur content.