Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Gene L. Ussery, Jr.
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0100

DEP File No. 0330045-009-AV
Crist Electric Generating Plant
Escambia County

Enclosed is Final Permit Number 0330045-009-AV. This Title V renewal permit authorizes Gulf Power Company to continue commercial operation of the Crist Electric Generating Plant in accordance with Title IV and Title V of the Clean Air Act Amendments of 1990. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were electronically mailed by Internet e-mail before the close of business on 12/28/04 to the person(s) listed:

Mr. Gene L. Ussery, Jr., Gulf Power Company*
Mr. Kennard Kosky, P.E. (kkosky@golder.com)
Mr. Kevin White, P.E., DEP-NWD (kevin.white@dep.state.fl.us)
Mr. G. Dwain Waters, QEP, Gulf Power Company (GDWATERS@southernco.com)

Clerk Stamp

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

Barbara J. Friday 12/28/04
(Clerk) (Date)

FINAL Determination

Title V Air Operation Permit Renewal
FINAL Title V Air Operation Permit No.: 0330045-009-AV
Gulf Power Company
Crist Electric Generating Plant

I. Comment(s).

No comments were received from the USEPA during their 45 day review period of the PROPOSED Permit.

II. Conclusion.

In conclusion, the permitting authority hereby issues the FINAL Permit.

STATEMENT OF BASIS

Gulf Power Company
Crist Electric Generating Plant
Facility ID No.: 0330045
Escambia County

Title V Air Operation Permit Renewal
FINAL Permit No.: 0330045-009-AV

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-213. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

This facility consists of six active fossil fuel fired steam generators (boilers) and two fly ash silos. Boilers 4 and 5 are substitution Acid Rain Phase I Units. Boilers 6 and 7 are Acid Rain Phase I Units. All six boilers are subject to the Acid Rain Phase II requirements. Natural gas is the primary fuel for boilers 2 and 3. Pulverized coal is the primary fuel for boilers 4, 5, 6 and 7. Fuel oil is used as supplemental fuel in all six of the boilers. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Emissions unit number -001 was a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 1". It was permanently removed from service on March 31, 2003. Emissions unit number -002 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 2". It is rated at a maximum heat input of 420 MMBtu/hour when firing natural gas and 320 MMBtu/hour when firing fuel oil. Natural gas is the primary fuel. Emissions unit number -003 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 3". It is rated at a maximum heat input of 550 million Btu per hour (MMBtu/hour) when firing natural gas and/or fuel oil. Natural gas is the primary fuel. Units 2 and 3 are regulated under Acid Rain, Phase II. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. Emissions from these boilers are uncontrolled. Units 2 and 3 are scheduled to be removed from service no later than May 1, 2006. The Department feels that additional periodic monitoring for particulate matter (PM) emissions is not needed for these units. For each of the past ten years, these units have burned fuel oil for less than 400 hours. Under the approval granted by an alternate sampling procedure (ASP 97-B-01) accepted by EPA, as long as these units do not burn liquid or solid fuel for greater than 400 hours per year, annual particulate matter tests are not required.

Emissions unit number -004 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 4". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Emissions unit number -005 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 5". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Both units are Phase I Substitution and Phase II Acid Rain Units. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from units -004 and -005 are controlled by hot side (Buell Model # Bal. 2x34n333-4-3p) and cold side (Buell Model # 1.1x48k33-1p) electrostatic precipitators.

Emissions unit number -006 is a Foster Wheeler front wall fired, dry bottom boiler designated as "Boiler Number 6". It is rated at a maximum heat input of 3,704.8 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate fuel oil (used as back-up fuel). Emissions unit number -007 is a Foster Wheeler front and rear wall fired, dry bottom boiler designated as "Boiler Number 7". It is rated at a maximum heat input of 6,406.4 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate fuel oil (used as back-up fuel). These emissions units are regulated under Acid Rain, Phase I. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from unit -006 are controlled by a cold side electrostatic precipitator (Wheelabrator Model # HaRDE). PM emissions from unit -007 are controlled by cold side Alstom Power electrostatic precipitators. NO_X emissions from units -006 and -007 are controlled by Foster Wheeler Low NO_x Burners.

Boilers 4, 5, 6 and 7 are utilizing CEMS for compliance purposes for NO_X, SO_2 and opacity.

Boilers 4, 5, 6 and 7 are subject to CAM for controlled emissions of particulate matter.

Compliance with the heat input limitations is through the use of on-site composite fuel sampling and analysis. The permittee may use vendor supplied data to determine the heat content of the natural gas.

Emissions unit number 8 consists of two Fly Ash Storage Silos. Fly ash collection systems from precipitators on boilers numbers 4, 5, 6 & 7, which deliver fly ash to three transfer tanks, are totally enclosed with no emission points. Three blowers pneumatically convey dry fly ash to 2 silos at a maximum solids rate of 150 tons per hour to either silo or to both. The majority of the solids (99.4%) settle by gravity upon entering the silo, the residual particulates are controlled by a baghouse on each silo. Each baghouse is a Pulse Jet Fabric Filter - model #100 - WMWC - 420 (IIG) manufactured by Flex-Kleen. Dry fly ash will be transported in closed tanker trucks away from the site (approximately 20% sold annually) or conditioned (12-15% water added) fly ash will be transported to an approved landfill area on the site. This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required and Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards. There is one baghouse on each silo. Historical test data presented by Gulf Power shows less than 2.2% opacity from these units for the past 5 years. Based on these results, the Department does not feel that additional periodic monitoring is necessary.

Based on the Title V permit renewal application received June 22, 2004, this facility is a major source of hazardous air pollutants (HAPs).

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

November 8, 2004

Mr. Gene L. Ussery, Jr.
V.P. Power Generation
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0100

Re: Title V Air Operation Permit Renewal
PROPOSED Permit Project No.: 0330045-009-AV
Renewal of Title V Air Operation Permit No.: 0330045-001-AV
Crist Electric Generating Plant

Dear Mr. Ussery:

One copy of the "PROPOSED PERMIT DETERMINATION" for the Crist Electric Generating Plant located on Pate Road, off of 10 Mile Road on Governors Bayou, Escambia County, is enclosed. This letter is only a courtesy to inform you that the DRAFT permit has become a PROPOSED permit.

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

If you should have any questions, please contact Jonathan Holtom, P.E., at 850/921-9531.

Sincerely,

Trina L. Vielhauer (electronically signed)

Trina L. Vielhauer
Chief
Bureau of Air Regulation

TV/h
Enclosures

E-mail Copy furnished to:
Mr. Kennard Kosky, P.E. (kkosky@golder.com)
Mr. Kevin White, P.E., DEP-NWD (kevin.white@dep.state.fl.us)
Mr. G. Dwain Waters, QEP, Gulf Power Company (GDWATERS@southernco.com)
U.S. EPA, Region 4 (INTERNET E-mail Memorandum)

PROPOSED PERMIT DETERMINATION

Gulf Power Company
Crist Electric Generating Plant
Proposed Permit No.: 0330045-009-AV

I. Public Notice.

An "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" to Gulf Power Company, for the Crist Electric Generating Plant located on Pate Road, off of 10 Mile Road on Governors Bayou, Escambia County was clerked on September 20, 2004. The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was published in The Pensacola News Journal on October 6, 2004. The DRAFT Title V Air Operation Permit was available for public inspection at the permitting authority's office in Tallahassee and the Department's Northwest District office in Pensacola. Proof of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was received on October 21, 2004.

II. Public Comment(s).

No Public Comments were received during the 30 (thirty)-day public comment period, however, comments were received from the Permittee. The comments were not considered significant enough to reissue the DRAFT Title V Permit and require another Public Notice, therefore, the DRAFT Title V Operation Permit was changed. Those comments, and minor administrative corrections, are addressed below.

A. Email from Mr. G. Dwain Waters dated October 19, 2004.

Comment 1. Section I. Facility Information: Subsection A. Facility Description. The description outlines 5 fossil fired steam generators.... The facility has 6; see Statement of Basis.

Response 1. The requested correction has been made.

Comment 2. Section I. Facility Information: Section II. Facility-wide Conditions. Item 15. Condition notes reference to Permit Shield in lieu of Condition 52 of Appendix TV-4, Conditions. Gulf Power sees no need for this condition and any reference to on-going litigation in a permit. There are no such litigations on-going with Gulf Power. Please remove condition.

Response 2. Please see **Comment 15.**

Comment 3. Section III. Emissions Units and Conditions. A.21. Heat Input. Please add to A.21 reference to recordkeeping provisions for daily records for fuel consumption, i.e. A. 31. Please note that for A. 31 (Units 2 & 3) natural gas is not currently referenced, only solid and liquid fuel. The condition as written only addresses fuel oil for these units.

Response 3. A cross-reference to Specific Condition **A.31.** has been added to Specific Condition **A.21.** No clarification is needed for Specific Condition **A.31.**, because it requires that records be kept for all fuels fired. It is not limited to "only fuel oil" or "only solid and liquid fuel". As a result of this comment, Specific Condition **A.21.** has been changed.

FROM:
A.21. Heat Input. Compliance with the heat input limitations specified in Specific Condition **A.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **B.25.c. & d.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

TO:
A.21. Heat Input. Compliance with the heat input limitations specified in Specific Condition **A.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **B.25.c. & d.**) (see Specific Condition **A.31.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

Comment 4. Section III Emissions Units and Conditions. A.31 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption.

Response 4. The Department recognizes that Gulf Power maintains daily fuel usage records on a 24-hour block basis and acknowledges that these records can be used to demonstrate compliance with the hourly heat input limit. It is also understood that there is an occasional potential for missing fuel sample reports for a number of different reasons (i.e. lost or contaminated fuel samples, lost sample reports, analyzer malfunction, etc.). As a result of this comment, the following Permitting Note has been added after Specific Condition **A.31.**:

> {Permitting Note: Daily records of fuel consumption are maintained on a 24-hour block (midnight to midnight) basis. Gulf Power will meet greater than a 95% daily sampling rate.}

Comment 5. Section III Emissions Units and Conditions. B.26. Heat Input. Please add to B.26 reference to recordkeeping provisions for daily records for fuel consumption, i.e. B.33.

Response 5. A cross-reference to Specific Condition **B.33.** has been added to Specific Condition **B.26.** As a result of this comment, Specific Condition **B.26.** has been changed:

FROM:
B.26. Heat Input. Compliance with the heat input limitations specified in Specific Condition **B.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **B.25.c. & d.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

TO:

B.26. Heat Input. Compliance with the heat input limitations specified in Specific Condition **B.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **B.25.c. & d.**) (see Specific Condition **B.33.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

Comment 6. Section III Emissions Units and Conditions. B.33. Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption. Gulf Power will meet greater than 95% daily sampling rate.

Response 6. As a result of this comment, the following Permitting Note has been added after Specific Condition **B.33.**:

> {Permitting Note: Daily records of fuel consumption are maintained on a 24-hour block (midnight to midnight) basis. Gulf Power will meet greater than a 95% daily sampling rate.}

Comment 7. Section III Emissions Units and Conditions. C.34. Heat Input. Please add to C.34 reference to recordkeeping provisions for daily records for fuel consumption, i.e. C.41.

Response 7. A cross-reference to Specific Condition **C.41.** has been added to Specific Condition **C.34.** As a result of this comment, Specific Condition **C.34.** has been changed.

FROM:
C.34. Determination of Compliance with Permitted Capacity. Compliance with the heat input limitations specified in Specific Condition **C.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **C.33.c. & d.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

TO:
C.34. Determination of Compliance with Permitted Capacity. Compliance with the heat input limitations specified in Specific Condition **C.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **C.33.c. & d.**) (see Specific Condition **C.41.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

Comment 8. Section III Emissions Units and Conditions. C.41 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption. Gulf Power will meet greater than 95% daily sampling rate.

Response 8. As a result of this comment, the following Permitting Note has been added after Specific Condition **C.41.**:

{Permitting Note: Daily records of fuel consumption are maintained on a 24-hour block (midnight to midnight) basis. Gulf Power will meet greater than a 95% daily sampling rate.}

Comment 9. Section IV. Acid Rain Part. Subsection A. E.U. ID. Please add Unit 001 to all references in this section. Gulf Power retains 35 SO_2 allowances per year for Unit 001, even after retirement under the Acid Rain Program.

Response 9. Unit 001 has been added back to the table.

Comment 10. Section IV. Acid Rain Part. Subsection A. 6. Please update DR list. Mr. W. Paul Bowers is currently the DR. Delete under alternative designated representative, Mr. Robert G. Moore and substitute Mr. Gene L. Ussery, Jr.

Response 10. As a result of this comment, Specific Condition **A.6.** was changed:

FROM:

A.6. Comments, notes, and justifications: The Designated Representative has changed from Frederick Kuester to G. Edison Holland, Jr. to Robert G. Moore to Bill M. Guthrie to Charles D. McCrary.

The alternative designated representatives have been changed to include Robert G. Moore and James O. Vick.

TO:

A.6. Comments, notes, and justifications: The Designated Representative has changed from Frederick Kuester to G. Edison Holland, Jr. to Robert G. Moore to Bill M. Guthrie to Charles D. McCrary to W. Paul Bowers.

The alternative designated representatives have been changed to include Gene L. Ussery, Jr. and James O. Vick.

Comment 11. Appendix CAM, Compliance Assurance Monitoring Plan. Emissions Unit 007. Please revise the averaging time from 6 minutes to 1 hour for excursion and 6 minutes to 3 hours for exceedance as referenced in the Indicator Range in Table IV. There is no justification for adoption of less than a 3 hour averaging period for monitoring CAM for particulate matter. This unit was CAM tested at 18% opacity at 0.052 lb/MMBtu per EPA CAM protocol.

Response 11. After extensive communications between Gulf Power and the Department, the CAM table for Unit 007 has been changed:

FROM:

TABLE 4. MONITORING APPROACH FOR UNIT -007

	Compliance Indicator
I. Indicator	Opacity of ESP exhaust.
Measurement Approach	COMS in ESP outlet duct.
II. Indicator Range	An excursion is defined as any 6-minute opacity average greater

	than 18%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. An exceedance of the Opacity limit occurs if the opacity is greater than 20% for any 6-minute average. An exceedance of the opacity limit will most likely occur before the PM limit is reached.
III. Performance Criteria	
A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
E. Data Collection Procedures	The DAS retains all 6-minute average opacity data.
F. Averaging Period	6-minute averages.

TO:

TABLE 4. MONITORING APPROACH FOR UNIT -007

	Compliance Indicator
IV. Indicator	Opacity of ESP exhaust.
Measurement Approach	COMS in ESP outlet duct.
V. Indicator Range	An excursion is defined as any 1-hour opacity average greater than 15%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. Note: Particulate matter compliance testing shall be conducted on a semi-annual basis in order to provide additional assurance that this excursion level remains protective of the PM limit. (See Specific Condition **C.23.b.**) {Permitting Note: After 18 months, the permittee may petition for removal of the semi-annual test requirement.}
VI. Performance Criteria	
A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.

D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
F. Data Collection Procedures	The DAS retains all 6-minute average opacity data.
F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

In addition, Specific Condition **C.23.** was changed:

FROM:
C.23. Annual Tests Required. Units -006 and -007 shall be tested annually for NO_X, SO_2, PM and ammonia slip emissions in accordance with the requirements listed below.
[Rule 62-297.310(7)(a)4., F.A.C.; and, 0330045-005-AC]

TO:
C.23. Tests Required.
a. Annual Tests Required. Units -006 and -007 shall be tested annually for NO_X, SO_2, PM and ammonia slip emissions in accordance with the requirements listed below.
b. Semi-annual Tests required. Unit -007 shall be tested semi-annually for PM emissions in accordance with the requirements listed below.
[Rule 62-297.310(7)(a)4., F.A.C.; 0330045-005-AC; and, Applicant Request.]

{Permitting Note: After 18 months, the permittee may petition for removal of the semi-annual test requirement.}

Comment 12. Appendix CAM, Compliance Assurance Monitoring Plan. Emissions Unit 004, 005, 006 & 007. Please clarify that startup, shutdown and other excess emission exemptions do not apply to CAM.

Response 12. The request to clarify that startup, shutdown and malfunction periods are not subject to the excursion ranges has been made. As a result of this comment, the following parenthetical note has been added to the CAM tables after the specified indicator range for each unit:

(other than periods of start up, shut down or malfunction)

B. Email memo from EPA Region 4 Received November 5, 2004.

Comment 13. CAM Plan. EPA reviewed the Compliance Assurance Monitoring (CAM) plan that was included as part of the Gulf Power - Plant Crist draft Title V permit (0330045-009-AV). It is our understanding that FDEP set the exceedance limits and excursion levels triggering action after an evaluation of emissions data provided by the applicant which was specific to Plant Crist. EPA finds the limits set for both the excursions and exceedances acceptable for this permitting action; however, it is our suggestion that Gulf Power continues to gather emissions data to better assess the correlation between opacity and particulate matter emissions and that FDEP reassess these limits once more data has been obtained.

Response 13. This comment has been addressed in the response to Comment 11. Gulf Power will conduct semi-annual particulate emissions tests in order to gather additional information. As a result of this comment, no further changes are required.

Comment 14. *Condition 3*: Please correct this condition to reference the requirements of Section 112(r).

Response 14. The requested correction has been made.

Comment 15. *Condition 15*: EPA reviewed the revised language sent to our office via email on November 4, 2004, and considers it adequate to address the conditions of the permit shield provided to the facility.

Response 15. As a result of this comment, Condition 15 has been changed:

FROM:
15. In lieu of Condition 52. of APPENDIX TV-4, TITLE V CONDITIONS, the following condition applies:

Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall, as of the effective date of the permit, be deemed compliance with any applicable requirements in effect, provided that the source included such applicable requirements in the permit application. Nothing in Rule 62-213.460, F.A.C., or in any permit shall alter or affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program.
[Rule 62-213.460, F.A.C.]

In addition, this permit shield does not currently encompass major or minor source construction permit requirements that are deemed applicable to the source as a result of ongoing litigation. The source shall not be shielded from any such requirements found to be applicable by the court, and in the event that such a finding is made, this will provide a basis for reopening the permit to establish a schedule for complying with these requirements. It is specifically recognized that this exception to the permit shield applies to a determination that major or minor new source construction permit requirements apply to the source. Nothing in the permit has made any specific finding of non-applicability of any PSD, NSPS, or SIP minor source review requirements for any modifications to which these requirements should have applied.

TO:
15. In lieu of Condition 52. of APPENDIX TV-4, TITLE V CONDITIONS, the following condition applies:

Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall, as of the effective date of the permit, be deemed compliance with any applicable requirements in effect, provided that the source included such applicable requirements in the permit application. Nothing in Rule 62-213.460, F.A.C., or in any permit shall alter or affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program. [Rule 62-213.460, F.A.C.]

In addition, this permit shield does not currently encompass major or minor source construction permit requirements that are deemed applicable to the source by a court of competent jurisdiction. The source shall not be shielded from any such requirements found, after the exhaustion of appeals, to be applicable by such court, and in the event that such a finding is made and the appeals therefrom are exhausted, this will provide a basis for reopening the permit to establish a schedule for complying with these requirements. Until such time as a final decision is reached after the exhaustion of appeals, no compliance schedule shall be necessary or required. Furthermore, the annual compliance certification shall not be required to address such matters until a final decision is reached. It is specifically recognized that this exception to the permit shield applies to a determination by such court, after exhaustion of appeals, that major or minor new source construction permit requirements apply to the source. Nothing in the permit has made any specific finding of non-applicability of any PSD, NSPS, or SIP minor source review requirements for any modifications to which these requirements should have applied.

III. Conclusion.

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

The permitting authority will issue the PROPOSED Permit Number 0330045-009-AV, with the changes noted above.

STATEMENT OF BASIS

Gulf Power Company
Crist Electric Generating Plant
Facility ID No.: 0330045
Escambia County

Title V Air Operation Permit Renewal
PROPOSED Permit No.: 0330045-009-AV

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-213. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

This facility consists of six active fossil fuel fired steam generators (boilers) and two fly ash silos. Boilers 4 and 5 are substitution Acid Rain Phase I Units. Boilers 6 and 7 are Acid Rain Phase I Units. All six boilers are subject to the Acid Rain Phase II requirements. Natural gas is the primary fuel for boilers 2 and 3. Pulverized coal is the primary fuel for boilers 4, 5, 6 and 7. Fuel oil is used as supplemental fuel in all six of the boilers. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Emissions unit number -001 was a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 1". It was permanently removed from service on March 31, 2003. Emissions unit number -002 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 2". It is rated at a maximum heat input of 420 MMBtu/hour when firing natural gas and 320 MMBtu/hour when firing fuel oil. Natural gas is the primary fuel. Emissions unit number -003 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 3". It is rated at a maximum heat input of 550 million Btu per hour (MMBtu/hour) when firing natural gas and/or fuel oil. Natural gas is the primary fuel. Units 2 and 3 are regulated under Acid Rain, Phase II. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. Emissions from these boilers are uncontrolled. Units 2 and 3 are scheduled to be removed from service no later than May 1, 2006. The Department feels that additional periodic monitoring for particulate matter (PM) emissions is not needed for these units. For each of the past ten years, these units have burned fuel oil for less than 400 hours. Under the approval granted by an alternate sampling procedure (ASP 97-B-01) accepted by EPA, as long as these units do not burn liquid or solid fuel for greater than 400 hours per year, annual particulate matter tests are not required.

Emissions unit number -004 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 4". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Emissions unit number -005 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 5". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Both units are Phase I Substitution and Phase II Acid Rain Units. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from units -004 and -005 are controlled by hot side (Buell Model # Bal. 2x34n333-4-3p) and cold side (Buell Model # 1.1x48k33-1p) electrostatic precipitators.

Emissions unit number -006 is a Foster Wheeler front wall fired, dry bottom boiler designated as "Boiler Number 6". It is rated at a maximum heat input of 3,704.8 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate fuel oil (used as back-up fuel). Emissions unit number -007 is a Foster Wheeler front and rear wall fired, dry bottom boiler designated as "Boiler Number 7". It is rated at a maximum heat input of 6,406.4 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate fuel oil (used as back-up fuel). These emissions units are regulated under Acid Rain, Phase I. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from unit -006 are controlled by a cold side electrostatic precipitator (Wheelabrator Model # HaRDE). PM emissions from unit -007 are controlled by cold side Buell electrostatic precipitators. NO_X emissions from units -006 and -007 are controlled by Foster Wheeler Low NO_x Burners.

Units 1 and 2 are utilizing CEMS for compliance purposes for NO_X, SO_2 and opacity. Units 4 and 5 are utilizing CEMS for compliance purposes for NO_X and SO_2.

Boilers 4, 5, 6 and 7 are subject to CAM for controlled emissions of particulate matter.

Compliance with the heat input limitations is through the use of on-site composite fuel sampling and analysis.

Emissions unit number 8 consists of two Fly Ash Storage Silos. Fly ash collection systems from precipitators on boilers numbers 4, 5, 6 & 7, which deliver fly ash to three transfer tanks, are totally enclosed with no emission points. Three blowers pneumatically convey dry fly ash to 2 silos at a maximum solids rate of 150 tons per hour to either silo or to both. The majority of the solids (99.4%) settle by gravity upon entering the silo, the residual particulates are controlled by a baghouse on each silo. Each baghouse is a Pulse Jet Fabric Filter - model #100 - WMWC - 420 (IIG) manufactured by Flex-Kleen. Dry fly ash will be transported in closed tanker trucks away from the site (approximately 20% sold annually) or conditioned (12-15% water added) fly ash will be transported to an approved landfill area on the site. This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required and Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards. There is one baghouse on each silo. Historical test data presented by Gulf Power shows less than 2.2% opacity from these units for the past 5 years. Based on these results, the Department does not feel that additional periodic monitoring is necessary.

Based on the Title V permit renewal application received June 22, 2004, this facility is a major source of hazardous air pollutants (HAPs).

Gulf Power Company
Crist Electric Generating Plant
Facility ID No.: 0330045
Escambia County

Title V Air Operation Permit
PROPOSED Permit No.: 0330045-009-AV

(Renewal of Initial Title V Air Operation Permit No.: 0330045-001-AV)

Permitting Authority

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

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

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

Title V Air Operation Permit

PROPOSED Permit No.: 0330045-009-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:
Gulf Power Company
500 Bay Front Parkway
Pensacola, Florida 32520-0100

PROPOSED Permit No.: 0330045-009-AV
Facility ID No.: 0330045
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Renewal

This permit is for the operation of the Crist Electric Generating Plant. This facility is located on Pate Road, off of 10 Mile Road on Governors Bayou, Escambia County, North of Pensacola.

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Phase II Acid Rain Permit Application/Compliance Plan Signed 06/01/04
Phase II Acid Rain NO_X Compliance Plan Signed 06/01/04
Revised Phase II Acid Rain NO_X Averaging Plan Signed 11/18/03
Appendix SO-1, Secretarial ORDER(s)
Appendix SS-1, Stack Sampling Facilities (version dated 10/7/96)
Appendix TV-4, Title V Conditions (version dated 2/12/02)
ASP Number 97-B-01
Scrivener's Order Correcting ASP Number 97-B-01 (dated July 9, 1997)
Appendix CAM, Compliance Assurance Monitoring Plan

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/jh

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of six fossil fuel fired steam generators (boilers) and two fly ash silos. Boilers 4 and 5 are substitution Acid Rain Phase I Units. Boilers 6 and 7 are Acid Rain Phase I Units. All five boilers are subject to the Acid Rain Phase II requirements. Natural gas is the primary fuel for boilers 2 and 3. Pulverized coal is the primary fuel for boilers 4, 5, 6 and 7. Fuel oil is used as supplemental fuel in all six of the boilers. Boiler 1 was permanently retired on March 31, 2003. Boilers 2 and 3 will be retired on, or before, May 1, 2006. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the Title V permit renewal application received June 22, 2004, this facility is a major source of hazardous air pollutants (HAPs).

The existing facility is a PSD-major source of air pollution in accordance with Rule 62-212.400, F.A.C.

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

Subsection B. Summary of Emissions Unit ID Numbers and Brief Descriptions.

E.U. ID No.	Brief Description
-001	Boiler Number 1 - 420 MMBtu/hour (retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hour **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hour **(to be retired by May 1, 2006)**
-004	Boiler Number 4 - 1,096.7 MMBtu/hour
-005	Boiler Number 5 - 1,096.7 MMBtu/hour
-006	Boiler Number 6 - 3,704.8 MMBtu/hour
-007	Boiler Number 7 - 6,406.4 MMBtu/hour
-008	Fly Ash Silos (2)
-009	Material Handling of Coal and Ash (See Appendix U-1)
-010	Fugitive PM Sources - On-site Vehicles (See Appendix U-1)
-011	General Purpose Internal Combustion Engines (See Appendix U-1)
-012	Cooling Towers (3) (See Appendix U-1)
-013	Fugitive PM Sources - sandblasting operations (See Appendix U-1)

Please reference the Permit Number, the Facility Identification Number, and the appropriate Emissions Unit(s) ID Number(s) on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The following documents are part of this permit:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Phase II Acid Rain Permit Application/Compliance Plan Signed 6/1/04
Phase II Acid Rain NO_X Compliance Plan Signed 6/1/04
Revised Phase II Acid Rain NO_X Averaging Plan Signed 11/18/03
Appendix SO-1, Secretarial ORDER(s)
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ASP Number 97-B-01
Scrivener's Order Correcting ASP Number 97-B-01 (dated July 9, 1997)
Appendix CAM, Compliance Assurance Monitoring Plan

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

These documents are provided to the permittee for informational purposes only:
Appendix H-1, Permit History / ID Number Transfers
Phase I Acid Rain Permits Issued December 27, 1994
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers (version dated 2/5/97)
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements

These documents are on file with the permitting authority:
Title V Permit Renewal Application Received June 22, 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 one copy when requested or otherwise appropriate. If desired, a copy of Appendix TV-4, Title V Conditions can be downloaded from the Division of Air Resources Management's Internet Web site located at the following address:
http://www.dep.state.fl.us/air/permitting/writertools/t5/TV-4.doc.

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. 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]

4. 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.]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. 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: No vapor emission control devices or systems are deemed necessary nor ordered by

the Department as of the issuance date of this permit.}
[Rule 62-296.320(1)(a), F.A.C.]

7. 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.]

8. Emissions of Unconfined Particulate Matter. Pursuant to Rules 62-296.320(4)(c)1., 3. & 4., F.A.C., reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the following requirements (see Condition 57. of APPENDIX TV-4, TITLE V CONDITIONS):

a) Ash leaving the facility will be hauled in closed container trucks. Ash being disposed of on plant property will be mixed with water as it is being loaded into the trucks for transport to the landfill.

b) The plant ash haul roads will be watered as necessary.

c) Grassing over each section of the ash landfill as it reaches its capacity.

d) Regular packing of the coal pile to reduce blowing dust and aid in the prevention of coal fires.

e) Application of a dust suppressant to the coal on the conveyor belts as necessary.

[Rule 62-296.320(4)(c)2., F.A.C.; and, Proposed by applicant in Title V permit renewal application received June 22, 2004.]

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. 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)}

11. The Department's Northwest District Office (Pensacola) telephone number for reporting problems, malfunctions or exceedances under this permit is 850/595-8364, day or night, and for emergencies involving a significant threat to human health or the environment is 850/413-9911. The Department's Northwest District Office (Pensacola) telephone number for routine business, including compliance test notifications, is 850/595-8364 during normal working hours.

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

Department of Environmental Protection
Northwest District Office
160 Governmental Center
Pensacola, Florida 32501-5794
Telephone: 850/595-8364
Fax: 850/595-8417

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

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

13. Any reports, data, notifications, certifications, and requests (other than Acid Rain Program Information) required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency, Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155
Fax: 404/562-9163 or 404/562-9164

14. 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.]

15. In lieu of Condition 52. of APPENDIX TV-4, TITLE V CONDITIONS, the following condition applies:

Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall, as of the effective date of the permit, be deemed compliance with any applicable requirements in effect, provided that the source included such applicable requirements in the permit application. Nothing in Rule 62-213.460, F.A.C., or in any permit shall alter or
affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program. [Rule 62-213.460, F.A.C.]

In addition, this permit shield does not currently encompass major or minor source construction permit requirements that are deemed applicable to the source by a court of competent jurisdiction. The source shall not be shielded from any such requirements found, after the exhaustion of appeals, to be applicable by such court, and in the event that such a finding is made and the appeals therefrom are exhausted, this will provide a basis for reopening the permit to establish a schedule for complying with these requirements. Until such time as a final decision is reached after the exhaustion of appeals, no compliance schedule shall be necessary or required. Furthermore, the annual compliance certification shall not be required to address such matters until a final decision is reached. It is specifically recognized that this exception to the permit shield applies to a determination by such court, after exhaustion of appeals, that major or minor new source construction permit requirements apply to the source. Nothing in the permit has made any specific finding of non-applicability of any PSD, NSPS, or SIP minor source review requirements for any modifications to which these requirements should have applied.

Section III. Emissions Units and Conditions.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-001	Boiler Number 1 - 420 MMBtu/hr (Retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hr **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hr **(to be retired by May 1, 2006)**

Emissions unit number -001 was permanently retired on March 31, 2003. Emissions unit number -002 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 2". It is rated at a maximum heat input of 420 million Btu per hour (MMBtu/hour) when firing natural gas and 320 MMBtu/hour when firing fuel oil. Natural gas is the primary fuel. Emissions unit number -003 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 3". It is rated at a maximum heat input of 550 million Btu per hour (MMBtu/hour) when firing natural gas and/or fuel oil. Natural gas is the primary fuel. Units -002 and -003 are regulated under Acid Rain, Phase II. Units -002 and -003 will be permanently retired by My 1, 2006.

{Permitting notes: These emissions units pre-date PSD regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. Emissions from these boilers are uncontrolled. Unit -002 began commercial operation on June 1, 1949. Unit -003 began commercial operation on September 1, 1952. The generator nameplate rating for unit -002 is 28 megawatts (MW). The generator nameplate rating for unit -003 is 39 MW. Units -002 and -003 share a common stack with units -004 and -005. Stack height = 450 feet, exit diameter = 18.0 feet, exit temperature = 290 °F, actual volumetric flow rate = 802,500 acfm.}

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
-002	420	Natural Gas
	320	No. 2 Fuel Oil
	320	No. 6 Fuel Oil
	320	On-Specification Used Oil
-003	550	Natural Gas
	550	No. 2 Fuel Oil
	550	No. 6 Fuel Oil
	550	On-Specification Used Oil

Note: When a blend of fuel oils and natural gas are fired, the heat input shall be prorated based on the percent heat input of each fuel.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.; and, 0330045-010-AC.]

A.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **A.25.**
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation - Fuels. The fuels that are allowed to be burned in these boilers, in any combination with respect to the proration of heat contents, are natural gas, No. 2 fuel oil, No. 6 fuel oil and on-specification used oil (see Specific Condition **A.35.**).
[Rule 62-213.410, F.A.C.; and, Applicant's requests in Title V permit renewal application received June 22, 2004.]

A.4. Hours of Operation. These emissions units may operate continuously, i.e. 8760 hours/year. For each emissions unit, the permittee shall maintain a daily operations log available for Department inspection that documents the total hours of annual operation, including an account of the hours operated on each of the allowable fuels.
[Rules 62-213.440 and 62-210.200(PTE), F.A.C.; and, Applicant's requests in Title V permit renewal application received June 22, 2004.]

Emission Limitations and Standards

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

A.5. Visible Emissions. Visible emissions shall not exceed 20 percent opacity except for one two-minute period per hour during which opacity shall not exceed 40 percent. Because units -002 and-003 share a common stack with units -004 and -005, visible emissions violations from the stack will be attributed to all five units unless opacity meter results show the specific unit causing the violation.
[Rule 62-296.405(1)(a), F.A.C.; and, AO17-249656, Specific Condition 8.]

A.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

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

{Permitting Note: Load changes may be demonstrated by monitoring megawatt output.}

A.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

{Permitting Note: The averaging time shall correspond to the cumulative sample time, as specified in the reference test method (see Specific Condition **A.18.**).}

A.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

A.9. Sulfur Dioxide - Liquid Fuel. When burning liquid fuel, sulfur dioxide emissions shall not exceed 1.98 pounds per million Btu heat input , as measured by applicable compliance methods.
[Rule 62-296.405(1)(c)1.e., F.A.C.]

A.10. Sulfur Dioxide - Sulfur Content. In order to ensure continuous compliance with the liquid fuel sulfur limit specified in Specific Condition **A.9.**, the liquid fuel sulfur content shall not exceed 1.8 percent, by weight, as measured by applicable test methods.
[Rule 62-213.440, F.A.C.; and, Applicant's Request.]

Excess Emissions

A.11. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

A.12. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

A.13. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

A.14. Sulfur Dioxide. Those emissions units not having an operating flue gas desulfurization device may monitor sulfur dioxide emissions by fuel sampling and analysis according to methods approved by the EPA. **Compliance with the liquid fuel sulfur limit will be verified by performing a daily, as-fired, fuel analysis.** This protocol is allowed because these emissions units do not have operating flue gas desulfurization devices. See Specific Conditions **A.10. and A.20.** of this permit.
[Rule 62-296.405(1)(f)1.b., F.A.C.; and, applicant request.]

Required Tests, Test Methods and Procedures

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

A.15. Annual Tests Required. Except as provided in Specific Conditions **A.28. – 30.**, units -002 and -003 shall conduct annual testing for particulate matter and visible emissions in accordance with the requirements listed below.
[Rule 62-297.310(7)(a)4., F.A.C.]

A.16. Visible Emissions. The test method for visible emissions shall be DEP Method 9 (see Specific Condition **A.17.**), incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.]

A.17. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rules 62-297.310 and 62-297.401, F.A.C.]

A.18. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310, and 62-297.401, F.A.C.]

A.19. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-

297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by this permit, the permittee elected to demonstrate compliance by performing a daily, as-fired, fuel analysis.** See Specific Conditions **A.10. and A.20.**
[Rules 62-213.440, 62-296.405(1)(e)3., 62-297.310 and 62-297.401, F.A.C.]

A.20. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.21. Heat Input. Compliance with the heat input limitations specified in Specific Condition **A.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **B.25.c. & d.**) (see Specific Condition **A.31.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The Acid Rain monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

A.22. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard (see Specific Condition **A.28.**);
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   c. Each NESHAP pollutant, if there is an applicable emission standard.
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

[Rule 62-297.310(7), F.A.C.; and SIP Approved]

Compliance Test Requirements

A.23. Determination of Process Variables.

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

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

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

A.24. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

A.25. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

A.26. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

A.27. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
   a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
   b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the

relationship between a proposed surrogate standard and an existing mass emission limiting standard.

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

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

{Permitting Note: Specific Condition A.18. specifies a minimum sample volume of 30 dry standard cubic feet.}

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

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

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings
		Max. deviation between readings	.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

A.28. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

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

[Rule 62-297.310(7)(a)4., F.A.C.]

A.29. Particulate Matter Testing - Annual. Annual compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s), other than during startup, for no more than 400 hours per year,; or,
c. only liquid fuel(s), other than during startup, for no more than 400 hours per year.

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

A.30. Particulate Matter Testing - Permit Renewal. Permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for no more than 400 hours per year; or,
c. only liquid fuel(s) for no more than 400 hours per year.

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

Recordkeeping and Reporting Requirements

A.31. The owner or operator shall maintain daily records of fuel consumption and each analysis that provides the heating value and sulfur content for all fuels fired. These records must be of sufficient detail to determine compliance with the conditions of this permit.
[Rules 62-213.440 and 62-4.070(3), F.A.C.]

{Permitting Note: Daily records of fuel consumption are maintained on a 24-hour block (midnight to midnight) basis. Gulf Power will meet greater than a 95% daily sampling rate.}

A.32. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

A.33. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

A.34. 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 on the results of each such test.

(b) The required test report shall be filed with the Department 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 to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

Miscellaneous Conditions.

A.35. Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power, not to exceed 10,000 gallons per calendar year in each boiler (units -002 & -003).

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Requirements: For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel. A generator, transporter, processor/re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications.
[40 CFR 279.72(a)]

Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(i) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.

(ii) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.

(iii) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see Specific Condition **A.20.**).

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
   (1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and
   (2) For each deposit of used oil, results of the analyses as required by the above conditions, or
   (3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above, the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

A.36. Common Conditions. These emissions units are also subject to the conditions in Subsection E.
[0330045-005-AC]

Subsection B. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-004	Boiler Number 4 (Substitution Phase I Acid Rain Unit)
-005	Boiler Number 5 (Substitution Phase I Acid Rain Unit)

Emissions unit number -004 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 4". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Emissions unit number -005 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 5". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Both units are Phase I Substitution and Phase II Acid Rain Units.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase I and Phase II. These emissions units pre-date PSD regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from units -004 and -005 are controlled by hot side (Buell Model # Bal. 2x34n333-4-3p) and cold side (Buell Model # 1.1x48k33-1p) electrostatic precipitators. Unit -004 began commercial operation on July 1, 1959. Unit -005 began commercial operation on June 1, 1961. The generator nameplate rating for unit -004 is 93 MW. The generator nameplate rating for unit -005 is 93 MW. Units -004 and -005 share a common stack with units -002 and -003. Stack height = 450 feet, exit diameter = 18.0 feet, exit temperature = 290 °F, actual volumetric flow rate = 802,500 acfm.}

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
-004	1,096.7	Coal
	1,096.7	Natural Gas
	1,096.7	No. 2 Fuel Oil
	1,096.7	On-Specification Used Oil
-005	1,096.7	Coal
	1,096.7	Natural Gas
	1,096.7	No. 2 Fuel Oil
	1,096.7	On-Specification Used Oil

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), 62-214.330 & 62-296.405, F.A.C.; and, permits AC17-2126, AC17-2127 & 0330045-010-AC.]

B.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **B.31.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation.

a. Fuels. The fuels that are allowed to be burned in these boilers are coal, natural gas, new No. 2 fuel oil and/or on-specification used oil (see Specific Condition **B.38.**). Fuel oil is only used for periods of start-up and as needed for flame stabilization. Also, on-site generated "oil contaminated soil" is periodically combusted for energy recovery purposes.

b. Other.
   i. Supplemental injection of "GAM 60" for purposes of maintaining boiler tube temperatures.
   ii. Supplemental injection of sodium carbonate or sodium sulfate at a rate of 440 pounds per hour as necessary to enhance the operation of the particulate control devices on these units

[Rule 62-213.410, F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

B.4. Hours of Operation. These emissions units may operate continuously, i.e. 8760 hours/year. For each emissions unit, the permittee shall maintain a daily operations log available for Department inspection that documents the total hours of annual operation, including an account of the hours operated on each of the allowable fuels.
[Rules 62-213.440 and 62-210.200(PTE), F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

Emission Limitations and Standards

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

{Permitting Note: Unless otherwise specified, the averaging times for Specific Conditions **B.5.-B.10.** are based on the specified averaging time of the applicable test method.}

B.5. Visible Emissions. Visible emissions shall not exceed 40 percent opacity. Because units -004 and -005 share a common stack with units -002 and -003, visible emissions violations from the stack will be attributed to all five units unless opacity meter results show the specific unit causing the violation.
[Rule 62-296.405(1)(a), F.A.C.; and, Secretarial ORDER(s) signed October 18, 1985 & January 3, 1986; and, AO17-211303, Specific Condition 10.]

B.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed for boiler cleaning and load changes, at units which have installed continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

{Permitting Note: Load changes may be demonstrated by monitoring megawatt output.}

B.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

B.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

B.9. Sulfur Dioxide - Solid Fuel. When burning solid fuel, sulfur dioxide emissions shall not exceed 5.90 pounds per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(c)2.c., F.A.C.]

B.10. Sulfur Dioxide - Liquid Fuel. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.40 pounds per million Btu heat input , as measured by applicable compliance methods.
[0330045-010-AC]

B.11. Sulfur Dioxide - Sulfur Content. In order to ensure continuous compliance with the liquid fuel sulfur limit specified in Specific Condition **B.10.**, the liquid fuel sulfur content shall not exceed 2.18 percent, by weight, as measured by applicable test methods.
[Rule 62-213.440, F.A.C.]

Excess Emissions

B.12. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

B.13. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

B.14. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

{Permitting Note: In accordance with the Acid Rain Phase II requirements, the following continuous monitors are installed on these units: SO_2, NO_X, CO_2 and stack gas flow.}

B.15. Continuous Monitors. For these emissions units, the permittee shall calibrate, operate and maintain continuous emissions monitoring systems (CEMS) for monitoring opacity, SO_2 and CO_2.
[Rule 62-296.405(1)(f)1., F.A.C.; and, Permit AO17-211303.]

B.16. Sulfur Dioxide. Those emissions units not having an operating flue gas desulfurization device may monitor sulfur dioxide emissions by fuel sampling and analysis according to methods approved by the EPA. **The permittee elected to satisfy the monitoring requirements using SO_2 continuous emissions monitors.**
[Rule 62-296.405(1)(f)1.b., F.A.C.; and, Applicant request.]

Required Tests, Test Methods and Procedures

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

B.17. Annual Tests Required. Units -004 and -005 shall be tested annually for SO_2 and PM emissions in accordance with the requirements listed below.
[Rule 62-297.310(7)(a)4., F.A.C.]

{Permitting Note: The annual SO_2 test that is required by Rule 62-297.310(7), F.A.C., can be done during the annual RATA as satisfaction of this requirement, provided all other testing requirements specified in the permit are met.}

B.18. Testing While Injecting Additives. The owner or operator shall conduct all emissions tests while injecting additives consistent with normal operating practices approved by the Department.
[Rule 62-213.440, F.A.C.]

B.19. Visible Emissions. The test method for visible emissions shall be DEP Method 9 (see Specific Condition **B.20.**), incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. **The permittee has elected to utilize a transmissometer (opacity meter) for demonstrating compliance with the visible emissions limit.** As long as the transmissometer is calibrated, maintained, and operated in accordance with Performance Specification 1 of 40 CFR 60, Appendix B (see Specific Condition **B.24.**), the annual test for visible emissions is not required.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

{Permitting Note: A transmissometer used to demonstrate compliance should record sufficient data so as to be equivalent to a Method 9 test. Method 9 requires determining an average based on 24 readings at 15-second intervals, thus, a six-minute average. The transmissometers in use at this facility make a permanent recording every six-minutes based on an average of readings taken every 15 seconds. After the 6-minute average is recorded, the individual readings are erased and a new 6-minute average is determined based on the next set of 24 individual readings. This 6-minute block recording is consistent with the requirements of Method 9.}

B.20. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rules 62-297.310 and 62-297.401, F.A.C.]

B.21. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310, and 62-297.401, F.A.C.]

B.22. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-297.310, and 62-297.401, F.A.C.; and, AO17-211303.]

{Permitting Note: The permittee has elected to demonstrate compliance by means of a continuous emissions monitoring system (CEMS). In addition to any other requirements associated with the operation and maintenance of these CEMS (i.e., Acid Rain requirements), operation of the CEMS shall be in accordance with the requirements listed below. The annual calibration RATA associated with these CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the

requirements of Rule 62-297.310, F.A.C., are met (i.e., prior test notification, proper test result submittal, etc.).}

B.23. Continuous SO_2 emission monitoring 24-hour averages are required to demonstrate compliance with the standards of the Department (see Specific Conditions **B.9. - B.11.**). A valid 24-hour average shall consists of no less than 18 hours of valid data capture per calendar day. In the event that valid data capture is interrupted, the permittee shall initiate as-fired fuel sampling to demonstrate compliance with the SO_2 emissions standard. The as-fired fuel sampling shall be initiated no later than 36 hours after the permittee has verified the problem or no later than 36 hours after the end of the affected calendar day. As-fired fuel sampling shall continue until such time as valid data capture is restored. In lieu of as-fired fuel sampling, the permittee may elect to demonstrate SO_2 emissions compliance by the temporary use of a spare SO_2 emissions monitor. The spare, previously calibrated, SO_2 emissions monitor must be installed and collecting data in the same time frame as required above for as-fired fuel sampling.

A quality control (QC) program must be maintained. At a minimum, the QC program must include written procedures which shall describe in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS.
2. Calibration Drift (CD) determination and adjustment of CEMS.
3. Preventative maintenance of CEMS (including spare parts inventory).
4. Data recording, calculations and reporting.
5. Accuracy audit procedures including sampling and analysis methods.
6. Program of corrective action for malfunctioning CEMS.

[Rules 62-213.440, 62-204.800(7)(e)5. and 62-296.405(1)(f)1.b., F.A.C.; and, AO17-211303.]

B.24. Continuous Monitor Performance Specifications. If continuous monitoring systems are required by rule or are elected by the permittee to be used for demonstrating compliance with the standards of the Department, they must be installed, maintained and calibrated, either:

(a) in accordance with the EPA performance specifications listed below. These Performance Specifications are contained in 40 CFR 60, Appendix B, and are adopted by reference in Rule 62-204.800, F.A.C.
   (1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.
   (2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources.
   (3) Performance Specification 3--Specifications and Test Procedures for CO_2 Continuous Emission Monitoring Systems in Stationary Sources. Or,
(b) in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Excess emissions pursuant to Rule 62-210.700, F.A.C., shall be determined using the 40 CFR part 75 CEMS.

[Rule 62-297.520, F.A.C.; 40 CFR 75; and, Applicant request.]

B.25. Fuel Sampling and Analysis. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard in the event that the SO_2 continuous emissions monitor is not able to capture valid data:

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

b. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using ASTM D2013-72 and either ASTM D3177-75 or ASTM D4239-85, or the latest edition, to analyze a representative sample of the blended as-fired pulverized coal.
c. Determine and record the density (using ASTM D 1298-80, or equivalent) and the calorific heat value in Btu per pound (using ASTM D 240-76, or the latest edition) of the fuel oil combusted.
d. Determine and record the calorific heat value in Btu per pound of the blended, as-fired pulverized coal using ASTM D2013-72 and either ASTM D2015-77 or D3286-(latest version), or the latest edition.
e. Record daily the amount of each fuel fired, the density of the fuel oil, the heating value of each fuel fired, and the percent sulfur content, by weight, of each fuel fired.
f. Utilize the information in a., b., c., d. and e., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

B.26. Heat Input. Compliance with the heat input limitations specified in Specific Condition **B.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **B.25.c. & d.**) (see Specific Condition **B.33.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

B.27. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

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

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

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

Compliance Test Requirements

B.28. Determination of Process Variables.

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

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

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

B.29. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to

this permit.
[Rule 62-297.310(6), F.A.C.]

B.30. 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.31. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

B.32. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
   a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
   b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

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

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

{Permitting Note: Specific Condition **B.21.** specifies a minimum sample volume of 30 dry standard cubic feet.}

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

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

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass	+/-2% ref. thermometer or equivalent, or thermometric points
Bimetallic thermometer	Quarterly	Calib. liq. in	5 degrees F glass thermometer
Thermocouple	Annually	ASTM Hg in glass	5 degrees F ref. thermometer, NBS calibrated reference and potentiometer
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

Recordkeeping and Reporting Requirements

B.33. The owner or operator shall maintain daily records of all fuels consumed.
[Rules 62-213.440 & 62-4.070(3), F.A.C.]

{Permitting Note: Daily records of fuel consumption are maintained on a 24-hour block (midnight to midnight) basis. Gulf Power will meet greater than a 95% daily sampling rate.}

B.34. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

B.35. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

B.36. A maintenance log of the continuous monitoring systems shall be kept showing the following:

a. Time out of service.
b. Calibration and adjustments.

[Rule 62-213.440, F.A.C.; and, AO17-211303, Specific Condition 8.]

B.37. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department 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 to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
   1. The type, location, and designation of the emissions unit tested.
   2. The facility at which the emissions unit is located.
   3. The owner or operator of the emissions unit.
   4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
   5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
   6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
   7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
   8. The date, starting time and duration of each sampling run.

9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required 'and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

Miscellaneous Conditions.

B.38. Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power Company, not to exceed 50,000 gallons per calendar year in each boiler (-004 & -005).

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Requirements: For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel. A generator, transporter, processor/re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications.
[40 CFR 279.72(a)]

Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(i) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.
(ii) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.
(iii) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see Specific Condition **B.25.**).

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
   (1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and
   (2) For each deposit of used oil, results of the analyses as required by the above conditions, or
   (3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above and the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

B.39. Compliance Assurance Monitoring. These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C.
[40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

B.40. Common Conditions. These emissions units are also subject to the conditions in Subsection E.
[0330045-005-AC]

Subsection C. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-006	Boiler Number 6 (Phase I Acid Rain Unit)
-007	Boiler Number 7 (Phase I Acid Rain Unit)

Emissions unit number -006 is a Foster Wheeler front wall fired, dry bottom boiler designated as "Boiler Number 6". It is rated at a maximum heat input of 3,704.8 million Btu per hour (MMBtu/hour) when firing pulverized coal and/or natural gas. Emissions unit number -007 is a Foster Wheeler front and rear wall fired, dry bottom boiler designated as "Boiler Number 7". It is rated at a maximum heat input of 6,406.4 million Btu per hour (MMBtu/hour) when firing pulverized coal and/or natural gas. Fuel oil is used as a back-up fuel in both units and for periods of start-up and flame stabilization.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase I. These emissions units pre-date PSD regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. Particulate matter emissions from unit -006 are controlled by a cold side electrostatic precipitator (Wheelabrator Model # HaRDE). Particulate matter emissions from unit -007 are controlled by cold side electrostatic precipitators designed by Alstom Power Inc. NO_X emissions from units -006 are controlled by Foster Wheeler Low NO_X Burners. NO_X emissions from unit -007 are controlled by Foster Wheeler Low NO_X Burners and by an SCR system designed to achieve no less than an 85% reduction in NO_X emissions as measured across the SCR unit inlet and outlet. The designed target ammonia slip level is 5 ppmv based on a 24-hour average. Unit -006 began commercial operation on May 1, 1970. Unit -007 began commercial operation on August 1, 1973. Units -006 and -007 share a common stack. Stack height = 450 feet, exit diameter = 23.2 feet, exit temperature = 320 °F, actual volumetric flow rate = 2,462,700 acfm.}

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
-006	3,704.8	Coal
	3,704.8	Natural Gas
	714.8	No. 2 Fuel Oil
	714.8	On-Specification Used Oil
-007	6,406.4	Coal
	6,406.4	Natural Gas
	1,282	No. 2 Fuel Oil
	1,282	On-Specification Used Oil

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), 62-214.330 & 62-296.405, F.A.C.; and, permits AC17-2126, AC17-2127 & 0330045-010-AC.]

C.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.39.**
[Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation.

a. Fuels. The fuels that are allowed to be burned in these boilers are coal, natural gas, new No. 2 fuel oil and/or on-specification used oil (see Specific Condition **C.48.**). Fuel oil is only used for periods of start-up and as needed for flame stabilization. Also, on-site generated "oil contaminated soil" is periodically combusted for energy recovery purposes.

b. Other.
   1. Supplemental injection of ammonia at a rate of 25 to 40 pounds per hour.
   2. Supplemental injection of sulfur trioxide at a rate of 4 to 20 ppm.
   3. Supplemental injection of "GAM 60" for purposes of maintaining boiler tube temperatures.

[Rule 62-213.410, F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

C.4. Hours of Operation. These emissions units may operate continuously, i.e. 8760 hours/year. For each emissions unit, the permittee shall maintain a daily operations log available for Department inspection that documents the total hours of annual operation, including an account of the hours operated on each of the allowable fuels.
[Rules 62-213.440 and 62-210.200(PTE), F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

Emission Limitations and Standards

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

{Permitting Note: Unless otherwise specified, the averaging times for Specific Conditions **C.5.-C.12.** are based on the specified averaging time of the applicable test method.}

C.5. Visible Emissions. Visible emissions from unit -006 shall not exceed 40 percent opacity. Visible emissions from unit -007 shall not exceed 20% based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27%. Because units -006 and -007 share a common stack, visible emissions violations from the stack will be attributed to both units unless opacity meter results show the specific unit causing the violation.
[Rule 62-296.405(1)(a), F.A.C.; and, Secretarial ORDER(s) signed May 12, 1988 & June 24, 1988; and, permits AC17-2234016, Specific Condition 14, AO17- 171806, Specific Condition 23 & 0330045-005-AC.]

C.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed for boiler cleaning and load changes, at units which have installed continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

{Permitting Note: Load changes may be demonstrated by monitoring megawatt output.}

C.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods. Particulate matter emissions from unit 6 shall not exceed 1,475 tons per year.
[Rule 62-296.405(1)(b), F.A.C.; and, AC17-234016.]

C.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

C.9. Sulfur Dioxide - Solid Fuel. When burning solid fuel, sulfur dioxide emissions shall not exceed 2.40 pounds per million Btu heat input, as measured by applicable compliance methods. When burning solid fuel, sulfur dioxide emissions from unit 6 shall not exceed 38,945 tons per year.
[Rule 62-296.405(1)(c)2.c., F.A.C.; and, 0330045-008-AC.]

C.10. Sulfur Dioxide - Liquid Fuel. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.40 pounds per million Btu heat input , as measured by applicable compliance methods.
[0330045-010-AC]

C.11. Sulfur Dioxide - Sulfur Content. In order to ensure continuous compliance with the liquid fuel sulfur limit specified in Specific Condition **C.10.**, the liquid fuel sulfur content shall not exceed 2.18 percent, by weight, as measured by applicable test methods.
[Rule 62-213.440, F.A.C.]

C.12. Nitrogen Oxides.

a. (Interim). Prior to implementing the required NO_X control strategy for Units -004, -005 and -006, the NO_X emissions from Unit -007 shall not exceed 0.15 lb/MMBtu of heat input based on a 30-day rolling average when the SCR system is operational with a catalyst temperature of at least 600° F. The permittee shall demonstrate compliance with data collected from the certified CEMS.

b. Permanent. After the required NO_X control strategy is implemented for Units -004, -005, and -006, the plant-wide NO_X standard specified in Subsection E. shall supersede this interim standard.
[0330045-005-AC]

Excess Emissions

C.13. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

C.14. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

C.15. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

SCR Operation

C.16. Selective Catalytic Reduction (SCR) System: The permittee shall operate and maintain an SCR system for Unit -007 to reduce emissions of nitrogen oxides (NO_X) as described in the application, approved drawings, plans, and other documents on file with the Department. The SCR system shall be designed to achieve no less than an 85% reduction in NO_X emissions as measured across the SCR unit inlet and outlet. The designed target ammonia slip level is 5 ppmv based on a 24-hour average. The storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[0330045-005-AC]

SCR Bypass Operation

C.17. SCR Bypass, Startup/Shutdown: During Unit -007 startup and shutdown, the SCR system may be bypassed in accordance with manufacturer's recommended procedures to allow for controlled catalyst heating and cooling. During startup, the SCR system shall be on line and functioning when the minimum operating temperature of the catalyst is achieved (≥ 600° F). During shutdown, the SCR system may be removed from service when the catalyst temperature drops below 600° F.
[Design; Rule 62-210.700, F.A.C. ; and, 0330045-005-AC.]

C.18. SCR Bypass, Catalyst Maintenance and Repair: The permittee may bypass the SCR system to perform catalyst maintenance and repair for up to 15 days per year during the non-ozone season. During such allowable bypass periods, the uncontrolled NO_X emissions from Unit -007 shall not exceed 0.35 lb/MMBtu based on a 24-hour average. The daily NO_X emission rates for these periods may be excluded from the plant-wide 30-day NO_X standard specified in Specific Condition **E.2.** The permittee shall notify the Compliance Authority in advance of the purpose of the SCR bypass, the expected dates of SCR bypass, and the expected duration of SCR bypass.
[Rules 62-210.700 and 62-4.070(3), F.A.C.; and, 0330045-005-AC.]

{Permitting Note: The ozone season is defined as May 1st through September 15th.}

Monitoring of Operations

{Permitting Note: In accordance with the Acid Rain Phase II requirements, the following continuous monitors are installed on these units: SO_2, NO_X, CO_2 and stack gas flow.}

C.19. Continuous Monitors. For these emissions units, the permittee shall calibrate, operate and maintain continuous monitoring systems for monitoring opacity, SO_2, NO_X and CO_2.
[Rule 62-296.405(1)(f)1., F.A.C.; and, Permits AC17-234016, AO17-171806 & 0330045-005-AC.]

C.20. COMS. The permittee shall install, calibrate, operate and maintain a continuous opacity monitoring system (COMS) to demonstrate compliance with the stack opacity standard. The COMS shall monitor and record data during all periods of Unit -007 operation including startup, shutdown, malfunction or emergency conditions, but not including continuous monitoring system breakdowns, repairs, or calibration checks.
[0330045-005-AC]

{Permitting Note: The existing COMS required by the Acid Rain program satisfies this requirement.}

C.21. NO_X CEMS: To demonstrate compliance with the emissions standards, the permittee shall install, calibrate, operate and maintain a continuous emissions monitoring system (CEMS) to continuously monitor and record the emissions of nitrogen oxides and an appropriate diluent gas (carbon dioxide or oxygen). The CEMS shall monitor and record data during all periods of Unit -007 operation including startup, shutdown, malfunction or emergency conditions, but not including continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments. For each calendar quarter, monitor availability shall be 95% or greater. If unable to achieve this level, the permittee shall submit a report identifying the problems in achieving 95% monitor availability and a plan of corrective actions. The permittee shall implement the reported corrective actions within the next calendar quarter.
[0330045-005-AC]

{Permitting Note: The existing NO_X CEMS required by the Acid Rain program satisfies this requirement.}

C.22. Sulfur Dioxide. Those emissions units not having an operating flue gas desulfurization device may monitor sulfur dioxide emissions by fuel sampling and analysis according to methods approved by the EPA. **The permittee elected to satisfy the monitoring requirements using SO_2 continuous emissions monitors.**
[Rule 62-296.405(1)(f)1.b., F.A.C.; Permits AC17-234016 & AO17-171806; and, Applicant request.]

Required Tests, Test Methods and Procedures

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

C.23. Tests Required.

a. Annual Tests Required. Units -006 and -007 shall be tested annually for NO_X, SO_2, PM and ammonia slip emissions in accordance with the requirements listed below.
b. Semi-annual Tests required. Unit -007 shall be tested semi-annually for PM emissions in accordance with the requirements listed below.

[Rule 62-297.310(7)(a)4., F.A.C.; 0330045-005-AC; and, Applicant Request.]

{Permitting Note: After 18 months, the permittee may petition for removal of the semi-annual test requirement.}

{Permitting Note: The annual SO_2 test that is required by Rule 62-297.310(7), F.A.C., can be done during the annual RATA as satisfaction of this requirement, provided all other testing requirements specified in the permit are met.}

C.24. Testing While Injecting Additives. The owner or operator shall conduct all emissions tests while injecting additives consistent with normal operating practices approved by the Department.
[Rule 62-213.440, F.A.C.]

C.25. Visible Emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. **The permittee has elected to utilize a transmissometer (opacity meter) for demonstrating compliance with the visible emissions limit**. As long as the transmissometer is calibrated, maintained, and operated in accordance with Performance Specification 1 of 40 CFR 60, Appendix B (see Specific Condition **C.32.**), the annual test for visible emissions is not required.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

{Permitting Note: A transmissometer used to demonstrate compliance should record sufficient data so as to be equivalent to a Method 9 test. Method 9 requires determining an average based on 24 readings at 15-second intervals, thus, a six-minute average. The transmissometers in use at this facility make a permanent recording every six-minutes based on an average of readings taken every 15 seconds. After the 6-minute average is recorded, the individual readings are erased and a new 6-minute average is determined based on the next set of 24 individual readings. This 6-minute block recording is consistent with the requirements of Method 9.}

C.26. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in

the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rules 62-297.310 and 62-297.401, F.A.C.]

C.27. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310, and 62-297.401, F.A.C.]

C.28. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards.
[Rules 62-213.440, 62-296.405(1)(e)3. 62-297.310 and 62-297.401, F.A.C.; and, Permits AC17-234016 and AO17-171806.]

{Permitting Note: The permittee has elected to demonstrate compliance by means of a continuous emissions monitoring system (CEMS). In addition to any other requirements associated with the operation and maintenance of these CEMS (i.e., Acid Rain requirements), operation of the CEMS shall be in accordance with the requirements listed below. The annual calibration RATA associated with these CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the requirements of Rule 62-297.310, F.A.C., are met (i.e., prior test notification, proper test result submittal, etc.).}

C.29. Continuous SO_2 emission monitoring 24-hour averages are required to demonstrate compliance with the standards of the Department (see Specific Conditions **C.9. - C.11.**). A valid 24-hour average shall consist of no less than 18 hours of valid data capture per calendar day. In the event that valid data capture is not available, the permittee shall initiate as-fired fuel sampling to demonstrate compliance with the SO_2 emissions standard. The as-fired fuel sampling shall be initiated no later than 36 hours after the permittee has verified the problem or no later than 36 hours after the end of the affected calendar day. Fuel sampling shall continue until such time as the valid data capture is restored. In lieu of as-fired fuel sampling the permittee may elect to demonstrate SO_2 emissions compliance by the temporary use of a spare SO_2 emissions monitor. The spare SO_2 emissions monitor must be installed and collecting data in the same time frame as required above for as-fired fuel sampling.

Maintain a QC program. At a minimum, the QC program must include written procedures which shall describe in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS.

2. Calibration Drift (CD) determination and adjustment of CEMS.
3. Preventative maintenance of CEMS (including spare parts inventory).
4. Data recording, calculations and reporting.
5. Accuracy audit procedures including sampling-and analysis methods.
6. Program of corrective action for malfunctioning CEMS.

[Rules 62-213.440, 62-204.800(7)(e)5., and 62-296.405(1)(f)1.b., F.A.C.; and, Permits AC17-234016 and AO17-171806.]

C.30. Nitrogen Oxides, Compliance Tests. During each federal fiscal year (October 1st to September 30th), the permittee shall conduct tests to demonstrate compliance with the emission limits contained in Specific Condition C.12. and with the design specification to achieve no less than an 85% reduction in the nitrogen oxide emission rate. The permittee shall concurrently test the SCR inlet and SCR outlet in accordance with EPA Method 7E as adopted by reference in Rule 62-204.800, F.A.C. Data collected during the annual NO_X RATA testing may be used to represent NO_X emissions at the SCR outlet. Alternatively, the permittee may submit data collected from the NO_X rate process monitors at the SCR inlet and SCR outlet, which are part of the ammonia injection system. The data shall be collected for at least three consecutive hours.
[Rules 62-4.070(3) & 62-297.310(7), F.A.C.; and, 0330045-005-AC.]

C.31. Ammonia Slip, Performance Tests. During each federal fiscal year, the permittee shall conduct tests to determine the ammonia slip rate in accordance with EPA Method CTM-027 or other methods approved by EPA. If tests show ammonia slip emissions are greater than the design target level specified in Specific Condition **C.16.** of this subsection, the permittee shall take corrective actions such as repair, addition of catalyst, replacement of catalyst, etc.
[Rules 62-4.070(3) & 62-297.310(7), F.A.C.; and, 0330045-005-AC.]

C.32. Continuous Monitor Performance Specifications. If continuous monitoring systems are required by rule or are elected by the permittee to be used for demonstrating compliance with the standards of the Department, they must be installed, maintained and calibrated, either:

(a) in accordance with the EPA performance specifications listed below. These Performance Specifications are contained in 40 CFR 60, Appendix B, and are adopted by reference in Rule 62-204.800, F.A.C.
  (1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.
  (2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources.
  (3) Performance Specification 3--Specifications and Test Procedures for CO_2 Continuous Emission Monitoring Systems in Stationary Sources. Or,

(b) in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Excess emissions pursuant to Rule 62-210.700, F.A.C., shall be determined using the 40 CFR part 75 CEMS.

[Rule 62-297.520, F.A.C.; 40 CFR 75; and, Applicant request.]

C.33. Fuel Sampling and Analysis. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard in the event that the SO_2 continuous emissions monitor is not able to capture valid data:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, to analyze a representative sample of the blended fuel following each fuel delivery.
b. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using ASTM D2013-72 and either ASTM D3177-75 or ASTM D4239-85, or the latest edition, to analyze a representative sample of the blended as-fired pulverized coal.
c. Determine and record the density (using ASTM D 1298-80, or equivalent) and the calorific heat value in Btu per pound (using ASTM D 240-76, or the latest edition) of the fuel oil combusted.
d. Determine and record the calorific heat value in Btu per pound of the blended, as-fired pulverized coal using ASTM D2013-72 and either ASTM D2015-77 or D3286-(latest version), or the latest edition.
e. Record daily the amount of each fuel fired, the density of the fuel oil, the heating value of each fuel fired, and the percent sulfur content, by weight, of each fuel fired.
f. Utilize the information in a., b., c., d. and e., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

C.34. Determination of Compliance with Permitted Capacity. Compliance with the heat input limitations specified in Specific Condition **C.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **C.33.c. & d.**) (see Specific Condition **C.41.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

C.35. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or

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

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   c. Each NESHAP pollutant, if there is an applicable emission standard.
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

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

Compliance Test Requirements

C.36. Determination of Process Variables.

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

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

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

C.37. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

C.38. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

C.39. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

C.40. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
   a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
   b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of

Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

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

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

{Permitting Note: Specific Condition C.21. specifies a minimum sample volume of 30 dry standard cubic feet.}

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

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

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass	+/-2% ref. thermometer or equivalent, or thermometric points
Bimetallic thermometer	Quarterly	Calib. liq. in	5 degrees F glass thermometer
Thermocouple	Annually	ASTM Hg in glass	5 degrees F ref. thermometer, NBS calibrated reference and potentiometer
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

Recordkeeping and Reporting Requirements

C.41. The owner or operator shall maintain daily records of all fuels consumed.
[Rules 62-213.440 and 62-4.070(3), F.A.C.]

{Permitting Note: Daily records of fuel consumption are maintained on a 24-hour block (midnight to midnight) basis. Gulf Power will meet greater than a 95% daily sampling rate.}

C.42. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

C.43. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

C.44. A maintenance log of the continuous monitoring systems shall be kept showing the following:
  a. Time out of service.
  b. Calibration and adjustments.

[Rule 62-213.440, F.A.C.; and, Permits AC17-234016 & AO17-171806.]

C.45. 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 on the results of each such test.
(b) The required test report shall be filed with the Department 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 to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
   1. The type, location, and designation of the emissions unit tested.
   2. The facility at which the emissions unit is located.
   3. The owner or operator of the emissions unit.
   4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
   5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
   6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
   7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
   8. The date, starting time and duration of each sampling run.

9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required `and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

C.46. Test Reports. The permittee shall prepare and submit reports for all required tests in accordance with the provisions of Rule 62-297.310(8), F.A.C. For each required test run, the report shall indicate the actual heat input rate (MMBtu/hour), the NO_X emission rate (lb/MMBtu) as recorded by the CEMS, the ammonia injection rate (lb/hour), and the ammonia slip rate. The report shall also include copies of the continuous monitoring records for opacity and NO_X emissions.
[Rule 62-297.310(8), F.A.C.; and, 0330045-005-AC.]

C.47. Quarterly Report.

a. NO_X Summary. For each calendar day during the reporting quarter, the permittee shall report the following information related to the NO_X CEMS for Unit -007:
   1. Hours of operation for Unit -007;
   2. Daily average NO_X emission rate, lb/MMBtu;
   3. 30-day average NO_X emission rate, lb/MMBtu; and
   4. Whether or not the day included a startup, shutdown, malfunction or bypass of the SCR.

   Identify the "F" factor used for any calculations, the method of determination, and type of fuel combusted. For each day that CEMS data was not obtained for at least 18 hours of Unit 7 operation, provide a justification for not obtaining sufficient data and describe the corrective actions taken to prevent this in the future. Identify any emissions data excluded from the calculation of emission rates due to startup, shutdown, or malfunction.

b. Opacity Summary. For each calendar day during the reporting quarter, the permittee shall report each 6-minute period in excess of the opacity standard.

c. Gas Sampling Grid (GSG). The permittee shall summarize any tests using the GSG that were conducted during the calendar quarter.

Each quarterly report is due within 30 days of the calendar quarter being reported.
[0330045-005-AC]

Miscellaneous Conditions.

C.48. Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power Company, not to exceed 50,000 gallons per calendar year in each boiler (-006 & -007).

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Requirements: For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel. A generator, transporter, processor/ re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of

Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications.
[40 CFR 279.72(a)]

Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(i) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.
(ii) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.
(iii) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see Specific Condition **C.25.**).

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
(1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and
(2) For each deposit of used oil, results of the analyses as required by the above conditions, or
(3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above and the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

C.49. Compliance Assurance Monitoring. These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C.
[40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

C.50. Common Conditions. These emissions units are also subject to the conditions in Subsection E.
[0330045-005-AC]

Subsection D. This section addresses the following emissions units.

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

-008 Fly Ash Storage Silos (2)

This emissions unit consists of two Fly Ash Storage Silos. The fly ash collection systems from the precipitators on boilers numbers 4, 5, 6 & 7, which deliver fly ash to the three transfer tanks, are totally enclosed (i.e. no emission points). Three blowers pneumatically convey dry fly ash to 2 silos at a maximum solids rate of 150 tons per hour to either silo or to both. The majority of the solids (99.4%) settles by gravity upon entering the silo and the residual particulates are controlled by a baghouse on each silo. Each baghouse is a Pulse Jet Fabric Filter - model #100 - WMWC - 420 (IIG) manufactured by Flex-Kleen. Dry fly ash will be transported off-site in closed tanker trucks (approximately 20% sold annually) or conditioned fly ash (12-15% water added) will be transported to an approved landfill area on-site.

{Permitting notes: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required, and Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards. There is one baghouse on each silo. Each silo has two vents. Stack height = 124.5 feet, exit dimensions = 18" x 24" rectangle, exit temperature = 100 °F, actual volumetric flow rate = 5,452 acfm per vent, velocity = 30 feet per second. The two silos were built between October 27, 1981 and June 1, 1983.}

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

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum operating rate is as follows:

Unit No.	Operating Rate
-008	150 Tons Per Hour of Fly Ash Transported to Either or Both Silos

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AC17-47675.]

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

D.3. Hours of Operation. Each fly ash storage silo may operate continuously, i.e. 8,760 hours per year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

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

D.4. Visible Emissions. Visible emissions from each baghouse vent (2 on each baghouse) shall be less than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AC17-47675.]

Excess Emissions

D.5. Excess emissions from this emissions unit resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

D.6. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Required Tests, Test Methods and Procedures

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

D.7. Annual Tests Required. Unit -008 must be tested annually for visible emissions in accordance with the requirements listed below.

D.8. Visible emissions. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

D.9. **Not federally enforceable.** Operating Rate During Testing. Compliance shall be demonstrated at an operating rate which typifies normal operation of the fly ash system. This operating rate may be lower than the maximum allowable operating rate. Should the Department feel that test results do not provide reasonable assurance that the source is capable of compliance at the permitted maximum operating rate, the Department may request that a visible emissions test be conducted at a higher operating rate up to the maximum allowable operating rate.
[January 16, 1984 letter modifying permit AO17-70422, Specific Condition 15.]

D.10. Applicable Test Procedures.
(a) Required Sampling Time.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
    c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2., F.A.C.]

D.11. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

[Rule 62-297.310(7), F.A.C.; and, SIP Approved.]

Recordkeeping and Reporting Requirements

D.12. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

D.13. Test Reports.

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

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

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

Subsection E. Common Conditions. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-001	Boiler Number 1 - 420 MMBtu/hour (retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hour **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hour **(to be retired by May 1, 2006)**
-004	Boiler Number 4 - 1,096.7 MMBtu/hour
-005	Boiler Number 5 - 1,096.7 MMBtu/hour
-006	Boiler Number 6 - 3,704.8 MMBtu/hour
-007	Boiler Number 7 - 6,406.4 MMBtu/hour

{Permitting Note: August 28, 2002, Gulf Power Company and the Florida Department of Environmental Protection entered into an agreement titles, "Agreement for the Purpose of Ensuring Compliance with the Ozone Ambient Air Quality Standards". This agreement is the basis for the following permit conditions.}

REQUIREMENTS OF THE AGREEMENT

E.1. Supplemental Conditions. The conditions of this section supplement all other valid air construction and operation permits for these units. These conditions are in addition to all other applicable permit conditions and regulations.
[Rule 62-4.070(3), F.A.C.; and, 0330045-005-AC]

E.2. Plant-Wide NO_X Limit. Emissions of nitrogen oxides (NO_X) from the combined operation of Units -004, -005, -006, and -007 shall not exceed 0.2 lb/MMBtu heat input based on a 30-day rolling average except for periods when Unit -007 is shutdown. The plant-wide daily NO_X emission rate shall be determined by the following equation:

$$\text{Plant-Wide Daily MMBtu-Weighted } NO_X \text{ Emission Rate} = \frac{\sum_{\text{Units 4, 5, 6, 7}} [(\text{Unit \# daily MMBtu}) \times (\text{Unit \# daily } NO_X \text{ CEMS Rate})]}{\sum_{\text{Units 4, 5, 6, 7}} (\text{Unit \# daily MMBtu})}$$

The "Unit # daily MMBtu" shall be determined by the daily as-burned fuel analysis and the fuel fired for each unit. The "Unit # daily NO_X CEMS Rate" shall be determined by the daily average of NO_X CEMS data for each unit and reported in terms of "lb/MMBtu heat input". The plant-wide daily NO_X emissions rate shall be determined each day regardless of the operating status for Unit -007. The plant-wide 30-day rolling NO_X average shall be determined for each 30 sequential Unit -007 operating days, which need not be consecutive. A Unit -007 operating day means any calendar day that Unit -007 operates a minimum of 18 hours. The Unit -007 daily NO_X CEMS rate may consist of less than 18 hours of data if this is due to CEMS malfunction or invalid CEMS data. When the catalyst temperature is below 600° F during a startup or shutdown, NO_X emissions data collected during such periods may be excluded from the daily NO_X average. In accordance with Specific Condition **C.18.**, NO_X emissions data collected during SCR bypass during the non-ozone season may be excluded from the daily NO_X average. The plant-wide NO_X emission standard shall be achieved by utilizing the SCR system for Unit -007 and implementing the selected NO_X control strategy for Units -004, -005, and -006. The effective date for the plant-wide NO_X emission standard is:

a. The startup date of the selected additional NO_X reduction project, (excluding an SCR project for Unit -006), but no later than May 1, 2006; or
b. The startup date of the SCR project for Unit -006, but no later than December 31, 2007.

For purposes of this condition, "startup date" shall mean the date that the permittee demonstrates initial compliance with the terms of the required air construction permit (or other Department approval) that authorized implementation of the additional NO_X reduction project. [Paragraphs 2, 3 and Exhibit B of the Agreement]
[0330045-005-AC]

E.3. NO<u></u>$_X$ CEMS. To demonstrate compliance with the plant-wide NO_X emissions standard, the permittee shall install, calibrate, operate and maintain continuous emissions monitoring systems (CEMS) to continuously monitor and record the emissions of nitrogen oxides and an appropriate diluent gas (carbon dioxide or oxygen) from Units -004, -005, -006, and -007.
[Exhibit B of the Agreement; and, 0330045-005-AC]

{Permitting Note: The existing NO_X CEMS required by the Acid Rain program satisfy this requirement.}

E.4. Quarterly Report. For each calendar day during the reporting quarter, the permittee shall report the following information related to the NO_X CEMS for Unit -007:

- Daily NO_X emission rate for each boiler, lb/MMBtu;
- Daily heat input rate for each boiler, MMBtu/day;
- 30-day plant-wide NO_X emissions rate, lb/MMBtu;
- Identify whether Unit -007 operated less than 18 hours;
- Identify the occurrence of a Unit -007 startup or shutdown; and
- Identify operation of Unit -007 with SCR bypass for catalyst maintenance or repair and the duration of bypass (hours).

Identify the "F" factor used for any calculations, the method of determination, and type of fuel combusted. For each day that CEMS data was not obtained for at least 18 hours of Unit -007 operation, provide a justification for not obtaining sufficient data and describe the corrective actions taken to prevent this in the future. Identify any emissions data excluded from the calculation of emission rates due to startup, shutdown, or malfunction.
[0330045-005-AC]

{Permitting Note: To achieve the plant-wide NO_X standard for the Crist Plant, Gulf Power Company will take the following additional actions.}

E.5. Unit Retirements. The Agreement requires the retirement of Unit -001 within 120 days of receiving a final order from the Public Service Commission that authorizes the recovery of costs associated with the pollution control equipment incurred pursuant to the Agreement though the Environmental Cost Recovery Clause. **(Unit -001 was retired on March 31, 2003.)** A final order is one that is no longer subject to review or appeal by a court of competent jurisdiction. The Agreement also requires the retirement of Units -002 and -003 on or before May 1, 2006.
[Paragraph 4 of the Agreement]

E.6. Additional NO_X Reduction Projects. The Agreement requires Gulf Power Company to conduct a variety of engineering studies to determine the feasibility of NO_X reduction technologies for one or more

of the three remaining coal-fired units (Units -004, -005, and -006). The studies and related unit-specific demonstration projects may include (but are not limited to) SCR, selective non-catalytic reduction (SNCR) technology, over-fired air (OFA) technology, natural gas re-burn technology, selective use of biomass fuel, etc. The studies must be complete by May 1, 2005. Before implementing any NO_X reduction technology or combination of technologies, Gulf Power Company must obtain written concurrence from the Department that the use thereof is reasonable and necessary to achieve the overall plant-wide NO_X emission standard. If a NO_X reduction technology or a combination of technologies other than an SCR project for Unit 6 is identified as appropriate, Gulf Power Company will implement the technology or combination of technologies on one or more of the three remaining coal-fired units by May 1, 2006. If an SCR project for Unit -006 is identified as the appropriate NO_X reduction technology, Gulf Power Company will implement, begin and continue operating the SCR system by December 31, 2007.
[Paragraph 2 of the Agreement]}

Section IV. Acid Rain Part.

Operated by: Gulf Power Company
ORIS Code: 641

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

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

E.U. ID No.	Brief Description
	(retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hour **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hour **(to be retired by May 1, 2006)**
-004	Boiler Number 4 - 1,096.7 MMBtu/hour
-005	Boiler Number 5 - 1,096.7 MMBtu/hour
-006	Boiler Number 6 - 3,704.8 MMBtu/hour
-007	Boiler Number 7 - 6,406.4 MMBtu/hour

A.1. The Phase II permit applications, the Phase II NO_X compliance plans and the Phase II NO_X averaging plans submitted for this facility, as approved by the Department, are a part of this permit (included as Attachments). The owners and operators of these Phase II acid rain units must comply with the standard requirements and special provisions set forth in the applications listed below:

a. DEP Form No. 62-210.900(1)(a), F.A.C., Signed 6/1/04.
b. DEP Form No. 62-210.900(1)(a)4., F.A.C., Signed 6/1/04.
c. DEP Form No. 62-210.900(1)(a)5., F.A.C., Signed 11/18/03.

[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 #	EPA ID	Year	2004	2005	2006	2007	2008
-001	**ID No. 01 1**	**SO_2 allowances, under Table 2 or 3 of 40 CFR 73**	35*	35*	35*	35*	35*
-002	**ID No. 02 2**	**SO_2 allowances, under Table 2 or 3 of 40 CFR 73**	3*	3*	3*	3*	3*

-003	**ID No. 03 3**	**SO_2 allowances, under Table 2 or 3 of 40 CFR 73**	4*	4*	4*	4*	4*

E.U. ID #	EPA ID	Year	2004	2005	2006	2007	2008
-004	**ID No. 04 4**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	2467*	2467*	2467*	2467*	2467*
		NO_X limit	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.52** lb/MMBtu. In addition, this unit shall not have an annual heat input **greater than 5,591,320** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				
-005	**ID No. 05 5**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	2430*	2430*	2430*	2430*	2430*
		NO_X limit	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.60** lb/MMBtu. In addition, this unit shall not have an annual heat input **greater than 5,479,586** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				
-006	**ID No. 06 6**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	8396*	8396*	8396*	8396*	8396*

E.U. ID #	EPA ID	Year	2004	2005	2006	2007	2008
-006 (cont')		**NO_X limit**	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.45** lb/MMBtu. In addition, this unit shall not have an annual heat input **less than 21,086,630** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				
-007	**ID No. 07 7**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	12522*	12522*	12522*	12522*	12522*
		NO_X limit	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.45** lb/MMBtu. In addition, this unit shall not have an annual heat input **less than 34,569,955** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				

* 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, 3, or 4 of 40 CFR 73.

Additional Requirements

1. Under the plan (NO_X Phase II averaging plan), the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

2. In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only after the Alabama Department of Environmental Management, the Jefferson County (Alabama) Department

of Health, the Georgia Department of Natural Resources and the Mississippi Department of Environmental Quality, have also approved this averaging plan.

3. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

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)1., 2. & 3., 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.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Where an applicable requirement of the Act is more stringent than applicable 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, F.A.C., Definitions – Applicable Requirements.]

A.6. Comments, notes, and justifications: The Designated Representative has changed from Frederick Kuester to G. Edison Holland, Jr. to Robert G. Moore to Bill M. Guthrie to Charles D. McCrary to W. Paul Bowers.

The alternative designated representatives have been changed to include Gene L. Ussery, Jr. and James O. Vick.

Reporting Requirements

A.7. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-4, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

A.8. Demonstration of Compliance With the Phase II NO_X Averaging Plan. The Designated Representative shall provide a copy of the demonstration of compliance, prepared in accordance with 40 CFR 76.11(d), to the Department within 60 (sixty) days after the end of the calendar year.
[Rule 62-213.440, F.A.C.]

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

{Permitting note: The U.S. EPA issues Acid Rain Phase I permits.}

The emissions unit(s) listed below are regulated under Acid Rain Part, Phase I

E.U. ID No.	Brief Description
-004	Boiler Number 4 – 1,096.7 MMBtu/hour (Substitution for Unit -007)
-005	Boiler Number 5 – 1,096.7 MMBtu/hour (Substitution for Unit -007)
-006	Boiler Number 6 – 3,704.8 MMBtu/hour
-007	Boiler Number 7 – 6,406.4 MMBtu/hour

B.1. The Phase I permits, issued by the U.S. EPA, are attached to this permit. The owners and operators of these Phase I acid rain units must comply with the standard requirements and special provisions set forth in the Phase I permits issued December 27, 1994.
[Chapter 62-213, F.A.C.]

B.2. Comments, notes, and justifications: None.

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

Gulf Power Company
Crist Electric Generating Plant

PROPOSED Permit No.: 0330045-009-AV
Facility ID No.: 0330045

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

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

	State Registration Number	Contents	Size (Gallons)
1.	1	#2 Diesel – Tractor Fuel	20,000
2.	3	#2 Diesel – Lighter Oil	100,000
3.	4	#2 Diesel – Lighter Oil	100,000
4.	5	#6 Bunker “C”	1,387,000
5.	6	#6 Bunker “C”	1,387,000
6.	7	#6 Bunker “C”	1,387,000
7.	8	Used Oil	15,000
8.	9	Lube Oil	7,000
9.	10	Lube Oil	7,000
10.	11	Waste Oil	12,000
11.	12	Lube Oil	7,000
12.	13	Lube Oil	4,000
13.	14	Lube Oil	4,000
14.	15	Lube Oil	3,000
15.	16	Sulfuric Acid	4,000
16.	17	Sulfuric Acid	6,000
17.	2R1	Gasoline	2,000
18.	--	Used Oil	300

Miscellaneous

19. Fire Safety Equipment
20. Vacuum Pumps
21. Laboratory Equipment
22. Welding Equipment
23. Gulf Power Company Generated Non-hazardous Boiler Chemical Cleaning Wastes
(Not to exceed 50 gallons per minute)

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

Gulf Power Company
Crist Electric Generating Plant

PROPOSED Permit No.: 0330045-009-AV
Facility ID No.: 0330045

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

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

E.U. ID No.	Brief Description of Emissions Units and/or Activity
-009	Material Handling of Coal and Ash
-010	Fugitive PM Sources – On-site Vehicles
-011	General Purpose Internal Combustion Engines
-012	Cooling Towers (3)
-013	Fugitive PM Sources – Sandblasting Operations

-009 Material Handling of Coal and Ash. Fugitive PM emissions generated from the transfer and handling of coal and ash. SCC: 3-05-101-03.

-010 Fugitive PM Sources. Fugitive PM emissions generated by haul trucks and other on-site vehicles. SCC: 3-05-101-50.

-011 General Purpose Internal Combustion Engines. Located for use at this source are miscellaneous internal combustion engines used to operate the following: welders, compressors, generators, water pumps, sweepers, and other auxiliary equipment.

-012 Cooling Towers. SCC: 3-90-900-04

-013 Fugitive PM Sources. Fugitive PM emissions generated by sandblasting operations. SCC: 3-05-101-99.

Appendix H-1, Permit History/ID Number Changes

(For Tracking Purposes Only)

Gulf Power Company — **PROPOSED Permit No.:** 0330045-009-AV
Crist Electric Generating Plant — **Facility ID No.:** 0330045

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Extended Date [2, 3]	Revised Date(s)
-001	Crist Unit #1	AO17-249656	5/19/94	1/15/96	8/14/96	
-002	Crist Unit #2	AO17-249656	5/19/94	1/15/96	8/14/96	
-003	Crist Unit #3	AO17-249656	5/19/94	1/15/96	8/14/96	
-004	Crist Unit #4	AO17-211303	4/17/92	4/1/97		
		Secretarial ORDER [1]	1/3/86			
		AC17-2126	10/15/75	3/1/77		
-005	Power Boiler No. 5	AO17-211303	4/17/92	4/1/97		
		Secretarial ORDER [1]	10/18/85			
		AC17-2127	10/15/75	3/1/77		
-006	Power Boiler No. 6	AC17-234016	10/7/93	12/1/94		
		AO17-171809	6/6/90	9/2/95	8/14/96	
		Secretarial ORDER [1]	5/12/88			
-007	Crist No. 7	AO17-171806	6/6/90	9/2/95	8/14/96	
		Secretarial ORDER [1]	6/24/88			
-008	Fly Ash Storage Silos (2)	AO17-234356	7/30/93	7/1/98		
		AC17-47675	10/27/81	2/1/83	6/1/83	
All	Initial Title V permit	0330045-001-AV	1/1/00	12/31/04		
-004, -055	Biomass project	0330045-004-AC	12/9/02	10/4/03		
-007	Addition of ESP and SCR	0330045-005-AC	3/3/03	12/1/05		
All	Ambient limit on SO_2	0330045-008-AC	5/18/04	-----		
All	Title V permit Renewal	0330045-009-AV	1/1/05	12/31/09		
All	Revision to SO_2 limit	0330045-010-AC	??			

1 Secretarial ORDER issued to relax semi-annual PM testing requirement to annual. Previous ORDERs had been issued to relax the Rule required quarterly testing requirement to semi-annual.
2 AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
3 AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., allows Title V Sources to operate under existing valid permits that were in effect at the time of application until the Title V permit becomes effective}

Referenced Attachments

Phase I Acid Rain Permits

Phase II Acid Rain Application/Compliance Plan

Phase II Acid Rain NO_X Compliance Plan

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

Appendix CAM, Compliance Assurance Monitoring Plan

Appendix SO-1, Secretarial ORDER(s)

Appendix SS-1, Stack Sampling Facilities (version dated 10/7/96)

Appendix TV-4, Title V Conditions (version dated 2/12/02)

ASP Number 97-B-01
(With Scrivener's Order Dated July 9, 1997)

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

Table 2-1, Compliance Requirements

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)]

<u>40 CFR 64.9 Reporting And Recordkeeping Requirements.</u>

15. <u>General reporting requirements.</u>

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. <u>General recordkeeping requirements.</u>

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]

Emissions Unit -004

1,096.7 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 1. MONITORING APPROACH FOR UNIT -004

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in the ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 27% (other than periods of start up, shut down or malfunction). Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. Note: Based on data submitted by the applicant, an exceedance of the PM limit will likely occur if the opacity is greater than 30% for 3 hours.
III.	Performance Criteria A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	E. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data.
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -005

1,096.7 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 2. MONITORING APPROACH FOR UNIT -005

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in the ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 28% (other than periods of start up, shut down or malfunction). Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. Note: Based on data submitted by the applicant, an exceedance of the PM limit will likely occur if the opacity is greater than 31% for 3 hours.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	F. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data.
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -006

3,704.8 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 3. MONITORING APPROACH FOR UNIT -006

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 33% (other than periods of start up, shut down or malfunction). Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. Note: Based on data submitted by the applicant, an exceedance of the PM limit will likely occur if the opacity is greater than 37% for 3 hours.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	G. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data.
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -007

6,406.4 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 4. MONITORING APPROACH FOR UNIT -007

	Compliance Indicator
I. Indicator	Opacity of ESP exhaust.
Measurement Approach	COMS in ESP outlet duct.
1. Indicator Range	An excursion is defined as any 1-hour opacity average greater than 15% (other than periods of start up, shut down or malfunction). Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. Note: Particulate matter compliance testing shall be conducted on a semi-annual basis in order to provide additional assurance that this excursion level remains protective of the PM limit. (See Specific Condition **C.23.b.**) {Permitting Note: After 18 months, the permittee may petition for removal of the semi-annual test requirement.}
II. Performance Criteria	
A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
H. Data Collection Procedures	The DAS retains all 6-minute average opacity data.
F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

One Energy Place
Pensacola, Florida 32520

Tel 850.444.6111

GULF POWER
A SOUTHERN COMPANY

Certified Mail

October 19, 2004

Mr. Jonathan K. Holtom, P.E.
Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Mail Station #5510
Tallahassee, Florida 32399-2400

Dear Mr.Holtom:

RE: CRIST ELECTRIC GENERATION FACILITY
DEP File No. 0330045-009-AV
Intent to Issue Title V Permit - Public Notice Affidavit

Attached, please find Gulf Power's proof of publication, i.e.,newspaper affidavit regarding the Public Notice of Intent to Issue Draft Title V Permit for Crist originally sent to Gene L. Ussery, Jr. (Gulf Power) on September 20, 2004. Due to Hurricane Ivan, Gulf did not receive the FDEP notice until September 29, 2004. Please note that Gulf Power did not receive the original affidavit regarding proof of publication from the Pensacola News Journal until today. A faxed version of this affidavit was sent to FDEP on October 14, 2004.

Please let me know if you have any questions regarding this matter and if you receive any public comments regarding this permit.

Sincerely,

Dwain Waters, QEP

G. Dwain Waters, Q.E.P.
Air Quality Programs Supervisor

Cc: Jim Vick, Gulf Power Company
Terry Wright, Gulf Power Company
John Dominey, Gulf Power Company
Sandra Veazey, FDEP, Northwest District

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In Touch.

Received GDL 10/19/04

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personally appeared **KAY CHASTAIN** and who on oath says that he/she is a a News Journal, a daily newspaper a County, Florida; that the attached copy ı the matter of **PUBLIC NOTICE** was : issues of **OCTOBER 6, 2004.** Affidavit ısacola News Journal is a newspaper cambia County, Florida, and that the said ontinuously published in said Escambia been entered as second class mail matter in said Escambia County, Florida, for a ; the first publication of the attached copy ırther says that he/she has neither paid nor or corporation any discount, rebate, ırpose of securing this advertisement for

ɜ me this **19TH DAY OF OCTOBER**

Notary Public

NIKKI G. WINDHAM
Notary Public-State of FL
Comm. Exp. Aug. 1, 2008
Comm. No. DD 342647

PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT AND A TITLE V AIR OPERATION PERMIT

DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Air Construction Permit No.: 0330045-010-AC
DRAFT Title V Air Operation Permit No.: 0330045-009-AV

Gulf Power Company - Crist Electric Generating Plant
Escambia County

Applicant: The applicant for this project is Gulf Power Company, One Energy Place, Pensacola, Florida 32520-0100. The applicant's responsible official is Mr. Gene L. Ussery, Jr., VP Power Generation.

Facility Location: The applicant operates a coal-fired electric generating plant, which is located on Pate Road, off of 10 Mile Road on Governors Bayou, Escambia County.

Project: The applicant submitted an application for a Title V Air Operation Permit renewal. This facility consists of six active fossil fuel fired steam generators (boilers) and two fly ash silos The facility is permitted to combust coal as the primary fuel and natural gas and distillate fuel oil as back-up fuel. The six boilers are regulated under Acid Rain Phase II. This permit will be a renewal Title V air operation permit for this facility.

Also include in this permitting action is an Air Construction Permit Revision, which is being issued to make a minor correction the SO2 emissions limit and to establish the method of compliance with the heat input limitations as the use of the on-site composite fuel sampling.

Permitting Authority: Applications for Air Construction Permits and for Title V Air Operation Permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-213 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to operate the facility. The Department of Environmental Protection is the Permitting Authority responsible for making a permit determination regarding this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301. The Permitting Authority's mailing address is: Department of Environmental Protection, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at the address indicated above for the Permitting Authority. The complete project file includes the Draft Permits, the Statement of Basis, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above or at the following email address: jonathan.holtom@dep.state.fl.us. A copy of the complete project file is also available at the Department of Environmental Protection's Northwest District Office at 160 Governmental Center, Pensacola, Florida 32501-5794 (Telephone: 850/595-8364).

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an Air Construction Permit and a Title V Air Operation Permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the facility will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-256, 62-257, 62-281, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Air Construction Permit, a Proposed Title V Air Operation Permit and subsequent Final Title V Air Operation Permit in accordance with the conditions of the Draft Permits unless a response received in accordance with the following procedures results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the Draft Air Construction Permit for a period of fourteen (14) days from the date of publication of this Public Notice. The Permitting Authority will accept written comments concerning the Draft Title V Air Operation Permit for a period of thirty (30) days from the date of publication of this Public Notice. Written comments must be provided to the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices (http://tlhora6.dep.state.fl.us/onw/) and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permits, the Permitting Authority shall revise the Draft Permits and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of this Public Notice or receipt of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address and telephone number of the petitioner; the name address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial rights will be affected by the agency determination; (c) A statement of how and when the petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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

Mediation: Mediation is not available for this proceeding.

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me this **19TH DAY OF OCTOBER**

Notary Public

NIKKI G. WINDHAM
Notary Public-State of FL
Comm. Exp. Aug. 1, 2008
Comm. No. DD 342647

Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices (http://tlhora6.dep.state.fl.us/onw/) and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permits, the Permitting Authority shall revise the Draft Permits and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

Mediation: Mediation is not available for this proceeding.

Objections: In addition to the above right to petition, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within sixty (60) days of the expiration of the Administrator's 45 (forty-five) day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to the issuance of any Permit. Any petition shall be based only on objections to the permit that were raised with reasonable specificity during the thirty (30) day public comment period provided in the Public Notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460. For more information regarding objections, visit the EPA Region 4 web site at: www.epa.gov/region4/air/permits.

Legal No. 67117 1T Oct. 6, 2004

Fax

To: Jonathan Holtom FDEP- Tallahassee
From: Duain Waters Gulf Power

Fax: (850) 922-6575
Date: 10/14/2004

Phone: (850) 921-9531
Pages: 2 with cover

Re: Crist Notice
CC:

☐ **Urgent** ☐ **For Review** ☐ **Please Comment** ☐ **Please Reply** ☐ **Please Recycle**

•Comments:

Please find faxversion of the Crist "Notice of Intent" published on Oct. 6, 2004. I only have this faxversion of the affidavit from Pensacola News Journal dated today. They said 3 days ago they mailed & faxed an earlier affidavit that we have not received yet. I will mail (certified) to you a better copy when we receive the original. You should already have the affidavits for Smith & Scholz mailed to you last week. Please call if you have questions or issues. Duain

PENSACOLA
News Journal
Informed. In Tune. In Touch.

Published Daily-Pensacola, Escambia County, FL

STATE OF FLORIDA
County of Escambia

Before the undersigned authority, personally appeared **KAY CHASTAIN** who is personally known to me and who on oath says that he/she is a representative of The Pensacola News Journal, a daily newspaper published in Pensacola in Escambia County, Florida; that the attached copy of advertisement, being a legal in the matter of **PUBLIC NOTICE** was published in said newspaper in the issues of **OCTOBER 6, 2004.** Affidavit further states that the said Pensacola News Journal is a newspaper published in Pensacola, in said Escambia County, Florida, and that the said newspaper has heretofore been continuously published in said Escambia County, Florida each day and has been entered as second class mail matter at the post office in Pensacola, in said Escambia County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and Affidavit further says that he/she has neither paid nor promised any person, firm, or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sworn to and subscribed before me this 14[TH] **DAY OF OCTOBER A.D., 2004.**

Nikki Richardson

Notary Public

NIKKI G. WINDHAM
Notary Public-State of FL
Comm. Exp. Aug. 1, 2008
Comm. No. DD 342647

PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT AND A TITLE V AIR OPERATION PERMIT

DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Air Construction Permit No.: 0330045-010-AC
DRAFT Title V Air Operation Permit No.: 0330045-009-AV

Gulf Power Company - Crist Electric Generating Plant
Escambia County

Applicant: The applicant for this project is Gulf Power Company, One Energy Place, Pensacola, Florida 32520-0100. [illegible]

[illegible]

Legal No. 67177 1T Oct. 6, 2004

Jonathan

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

GULF POWER COMPANY
Crist Electric Generating Plant

Petitioner,

v.

OGC #04-1741
DEP Permit 0330045-009-AV

DEPARTMENT OF ENVIRONMENTAL PROTECTION,

Respondent.

______________________________/

ORDER GRANTING REQUEST FOR EXTENSION
OF TIME TO FILE PETITION FOR HEARING

This cause has come before the Florida Department of Environmental Protection upon receipt of a request made by Petitioner PROGRESS ENERGY FLORIDA, INC., to grant an extension of time to file a petition for an administrative hearing to allow time to discuss with FDEP several specific permit conditions for its facility in Escambia County, Florida. Because the request shows good cause for the extension of time,

IT IS ORDERED:

The request for an extension of time to file a petition for administrative proceeding is granted. Petitioner shall have until **November 1, 2004**, to file a petition in this matter. Filing shall be complete on receipt by the Office of General Counsel, Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

DONE AND ORDERED on this 18th day of October, 2004, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Jack Chisolm

JACK CHISOLM, Deputy General Counsel
3900 Commonwealth Boulevard. M.S. 35
Tallahassee, Florida 32399-3000
850-245-2242 facsimile 850-245-2302

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via _ U. S. Mail ✓ facsimile ✓ or ly, this 18th day of October, 2004, to:

Angela R. Morrison, Esquire
Hopping Green & Sams, P.A.
Post Office Box 6526
Tallahassee, FL 32314

Facsimile 850-224-8551

W. Douglas Beason, Assistant General Counsel
STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION
3900 Commonwealth Boulevard - Mail Station 35
Tallahassee, FL 32399-3000
850-245-2242 facsimile 850-245-2302

with a courtesy copy to:

Trina L. Vielhauer
Chief
Bureau of Air Regulation

facsimile: 850-921-9533

Jonathan

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

OGC CASE NO.:
FDEP Draft Permit No.: 0330045-009-AV

Gulf Power Company
Crist Electric Generating Plant
Escambia County, Florida

______________________________________/

REQUEST FOR ENLARGEMENT OF TIME

By and through undersigned counsel, Gulf Power Company (Gulf Power) hereby requests, pursuant to Florida Administrative Code Rule 62-110.106(4), an enlargement of time, to and including November 15, 2004, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, Gulf Power states the following:

1. On or about September 29, 2004, Gulf Power Company received from the Department of Environmental Protection ("Department") an "Intent to Issue Title V Air Operation Permit Renewal" and accompanying "Draft Permit," (Draft Permit No. 0330045-009), for the Crist Electric Generating Plant, located on Governors Bayou off 10 Mile Road in Pensacola, Escambia County, Florida.

2. Based on Gulf Power's initial review, the Draft Permit and associated documents contain several provisions that warrant clarification or corrections.

3. This request is filed simply as a protective measure to avoid waiver of Gulf Power's right to challenge certain conditions contained in the Draft Title V Permit. Grant of this request will not prejudice either party, but will further their mutual interest and hopefully avoid the need to file a Petition and proceed to a formal administrative hearing.

WHEREFORE, Gulf Power Company respectfully requests that the time for filing of a Petition for Administrative Proceedings in regard to the Department's Intent to Issue Title V Air Operation Permit No. 0330045-009-AV be formally extended to and including November 15, 2004.

RESPECTFULLY SUBMITTED this 13th day of October, 2004.

By: ____________________

Angela R. Morrison
Fla. Bar No. 0855766
Hopping, Green & Sams, P.A.
123 South Calhoun Street
Post Office Box 6526
Tallahassee, FL 32314
(850) 222-7500
(850) 224-8551 Faxsimile

Attorneys for Gulf Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by Hand Delivery to Kathy Carter, Agency Clerk, and Doug Beason, General Counsel, Florida Department of Environmental Protection, 3900 Commonwealth Boulevard, Suite 300, Tallahassee, Florida 32399-3000; and Trina Vielhauer, Florida Department of Environmental Protection, Division of Air Resource Management, 111 S. Magnolia Drive, Suite 23, Tallahassee, Florida 32399 this 13th day of October, 2004.

____
Angela R. Morrison

STATEMENT OF BASIS

Gulf Power Company
Crist Electric Generating Plant
Facility ID No.: 0330045
Escambia County

Title V Air Operation Permit Renewal
DRAFT Permit No.: 0330045-009-AV

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-213. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

This facility consists of six active fossil fuel fired steam generators (boilers) and two fly ash silos. Boilers 4 and 5 are substitution Acid Rain Phase I Units. Boilers 6 and 7 are Acid Rain Phase I Units. All six boilers are subject to the Acid Rain Phase II requirements. Natural gas is the primary fuel for boilers 2 and 3. Pulverized coal is the primary fuel for boilers 4, 5, 6 and 7. Fuel oil is used as supplemental fuel in all six of the boilers. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Emissions unit number -001 was a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 1". It was permanently removed from service on March 31, 2003. Emissions unit number -002 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 2". It is rated at a maximum heat input of 420 MMBtu/hour when firing natural gas and 320 MMBtu/hour when firing fuel oil. Natural gas is the primary fuel. Emissions unit number -003 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 3". It is rated at a maximum heat input of 550 million Btu per hour (MMBtu/hour) when firing natural gas and/or fuel oil. Natural gas is the primary fuel. Units 2 and 3 are regulated under Acid Rain, Phase II. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. Emissions from these boilers are uncontrolled. Units 2 and 3 are scheduled to be removed from service no later than May 1, 2006. The Department feels that additional periodic monitoring for particulate matter (PM) emissions is not needed for these units. For each of the past ten years, these units have burned fuel oil for less than 400 hours. Under the approval granted by an alternate sampling procedure (ASP 97-B-01) accepted by EPA, as long as these units do not burn liquid or solid fuel for greater than 400 hours per year, annual particulate matter tests are not required.

Emissions unit number -004 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 4". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Emissions unit number -005 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 5". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Both units are Phase I Substitution and Phase II Acid Rain Units. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from units -004 and -005 are controlled by hot side (Buell Model # Bal. 2x34n333-4-3p) and cold side (Buell Model # 1.1x48k33-1p) electrostatic precipitators.

Emissions unit number -006 is a Foster Wheeler front wall fired, dry bottom boiler designated as "Boiler Number 6". It is rated at a maximum heat input of 3,704.8 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate fuel oil (used as back-up fuel). Emissions unit number -007 is a Foster Wheeler front and rear wall fired, dry bottom boiler designated as "Boiler Number 7". It is rated at a maximum heat input of 6,406.4 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate fuel oil (used as back-up fuel). These emissions units are regulated under Acid Rain, Phase I. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from unit -006 are controlled by a cold side electrostatic precipitator (Wheelabrator Model # HaRDE). PM emissions from unit -007 are controlled by cold side Buell electrostatic precipitators. NO_X emissions from units -006 and -007 are controlled by Foster Wheeler Low NO_x Burners. ~~Emissions unit –006 contains a PM limitation of 1,475 tons per year. This limit was established by a construction permit that was issued (in 1993) to install a new electrostatic precipitator. It was calculated based on the allowable emission limit, the maximum demonstrated heat input rate at that time, and the assumption of continuous operation (8,760 hours per year). With the issuance of this permit, a slightly higher (but now federally enforceable) heat input rate has been established. Even though the maximum potential PM emissions are now 1,623 tons per year, compliance with the enforceable 1,475 ton per year limit will be assured based on the low historical particulate matter emissions test results (see table below).~~

Unit #	Steady-state	Soot-blowing
4	0.011	0.016
5	0.039	0.035
6	0.007	0.010
7	0.041	0.062

Boilers 4, 5, 6 and 7 are utilizing CEMS for compliance purposes for NO_X, SO_2 and opacity.

Boilers 4, 5, 6 and 7 are subject to CAM for controlled emissions of particulate matter.

Compliance with the heat input limitations is through the use of on-site composite fuel sampling and analysis.

Emissions unit number 8 consists of two Fly Ash Storage Silos. Fly ash collection systems from precipitators on boilers numbers 4, 5, 6 & 7 to three transfer tanks are totally enclosed with no emission points. Three blowers pneumatically convey dry fly ash to 2 silos at a maximum solids rate of 150 tons per hour to either silo or to both. The majority of the solids (99.4%) settles by gravity upon entering the silo, the residual particulates are controlled by a baghouse on each silo. Each baghouse is a Pulse Jet Fabric Filter - model #100 - WMWC - 420 (IIG) manufactured by Flex-Kleen. Dry fly ash will be transported in closed tanker trucks away from the site (approximately 20% sold annually) or conditioned (12-15% water added) fly ash will be transported to an approved landfill area on the site. This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required and Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards. There is one baghouse on each silo. Historical test data presented by Gulf Power shows less than 2.2% opacity from these units for the past 5 years. Based on these results, the Department does not feel that additional periodic monitoring is necessary.

Based on the Title V permit renewal application received June 22, 2004, this facility is a major source of hazardous air pollutants (HAPs).

Gulf Power Company
Crist Electric Generating Plant
Facility ID No.: 0330045
Escambia County

Title V Air Operation Permit
DRAFT Permit No.: 0330045-009-AV

(Renewal of Initial Title V Air Operation Permit No.: 0330045-001-AV)

<u>Permitting Authority</u>
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

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

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

Title V Air Operation Permit

DRAFT Permit No.: 0330045-009-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:
Gulf Power Company
500 Bay Front Parkway
Pensacola, Florida 32520-0100

DRAFT Permit No.: 0330045-009-AV
Facility ID No.: 0330045
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Renewal

This permit is for the operation of the Crist Electric Generating Plant. This facility is located on Pate Road, off of 10 Mile Road on Governors Bayou, Escambia County, North of Pensacola.

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Phase II Acid Rain Permit Application/Compliance Plan Signed 06/01/04
Phase II Acid Rain NO_X Compliance Plan Signed 06/01/04
Revised Phase II Acid Rain NO_X Averaging Plan Signed 11/18/03
Appendix SO-1, Secretarial ORDER(s)
Appendix SS-1, Stack Sampling Facilities (version dated 10/7/96)
Appendix TV-4, Title V Conditions (version dated 2/12/02)
ASP Number 97-B-01
Scrivener's Order Correcting ASP Number 97-B-01 (dated July 9, 1997)
Appendix CAM, Compliance Assurance Monitoring Plan

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/jh

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of five fossil fuel fired steam generators (boilers) and two fly ash silos. Boilers 4 and 5 are substitution Acid Rain Phase I Units. Boilers 6 and 7 are Acid Rain Phase I Units. All five boilers are subject to the Acid Rain Phase II requirements. Natural gas is the primary fuel for boilers 2 and 3. Pulverized coal is the primary fuel for boilers 4, 5, 6 and 7. Fuel oil is used as supplemental fuel in all five of the boilers. Boiler 1 was permanently retired on March 31, 2003. Boilers 2 and 3 will be retired on, or before, May 1, 2006. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the Title V permit renewal application received June 22, 2004, this facility is a major source of hazardous air pollutants (HAPs).

The existing facility is a PSD-major source of air pollution in accordance with Rule 62-212.400, F.A.C.

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

Subsection B. Summary of Emissions Unit ID Numbers and Brief Descriptions.

E.U. ID No.	Brief Description
-001	Boiler Number 1 - 420 MMBtu/hour (retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hour **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hour **(to be retired by May 1, 2006)**
-004	Boiler Number 4 - 1,096.7 MMBtu/hour
-005	Boiler Number 5 - 1,096.7 MMBtu/hour
-006	Boiler Number 6 - 3,704.8 MMBtu/hour
-007	Boiler Number 7 - 6,406.4 MMBtu/hour
-008	Fly Ash Silos (2)
-009	Material Handling of Coal and Ash (See Appendix U-1)
-010	Fugitive PM Sources - On-site Vehicles (See Appendix U-1)
-011	General Purpose Internal Combustion Engines (See Appendix U-1)
-012	Cooling Towers (3) (See Appendix U-1)
-013	Fugitive PM Sources - sandblasting operations (See Appendix U-1)

Please reference the Permit Number, the Facility Identification Number, and the appropriate Emissions Unit(s) ID Number(s) on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The following documents are part of this permit:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Phase II Acid Rain Permit Application/Compliance Plan Signed 6/1/04
Phase II Acid Rain NO_X Compliance Plan Signed 6/1/04
Revised Phase II Acid Rain NO_X Averaging Plan Signed 11/18/03
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ASP Number 97-B-01
Scrivener's Order Correcting ASP Number 97-B-01 (dated July 9, 1997)
Appendix CAM, Compliance Assurance Monitoring Plan

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

These documents are provided to the permittee for informational purposes only:
Appendix H-1, Permit History / ID Number Transfers
Phase I Acid Rain Permits Issued December 27, 1994
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers (version dated 2/5/97)
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements

These documents are on file with the permitting authority:
Title V Permit Renewal Application Received June 22, 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 one copy when requested or otherwise appropriate. If desired, a copy of Appendix TV-4, Title V Conditions can be downloaded from the Division of Air Resources Management's Internet Web site located at the following address:
http://www.dep.state.fl.us/air/permitting/writertools/t5/TV-4.doc.

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. Prevention of Accidental Releases (Section 112I 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]

4. 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.]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. 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: No vapor emission control devices or systems are deemed necessary nor ordered by

the Department as of the issuance date of this permit.}
[Rule 62-296.320(1)(a), F.A.C.]

7. 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.]

8. Emissions of Unconfined Particulate Matter. Pursuant to Rules 62-296.320(4)(c)1., 3. & 4., F.A.C., reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the following requirements (see Condition 57. of APPENDIX TV-4, TITLE V CONDITIONS):

a) Ash leaving the facility will be hauled in closed container trucks. Ash being disposed of on plant property will be mixed with water as it is being loaded into the trucks for transport to the landfill.

b) The plant ash haul roads will be watered as necessary.

c) Grassing over each section of the ash landfill as it reaches its capacity.

d) Regular packing of the coal pile to reduce blowing dust and aid in the prevention of coal fires.

e) Application of a dust suppressant to the coal on the conveyor belts as necessary.

[Rule 62-296.320(4)(c)2., F.A.C.; and, Proposed by applicant in Title V permit renewal application received June 22, 2004.]

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. 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)}

11. The Department's Northwest District Office (Pensacola) telephone number for reporting problems, malfunctions or exceedances under this permit is 850/595-8364, day or night, and for emergencies involving a significant threat to human health or the environment is 850/413-9911. The Department's Northwest District Office (Pensacola) telephone number for routine business, including compliance test notifications, is 850/595-8364 during normal working hours.

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

Department of Environmental Protection
Northwest District Office
160 Governmental Center
Pensacola, Florida 32501-5794
Telephone: 850/595-8364
Fax: 850/595-8417

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

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

13. Any reports, data, notifications, certifications, and requests (other than Acid Rain Program Information) required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency, Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155
Fax: 404/562-9163 or 404/562-9164

14. 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.]

15. In lieu of Condition 52. of APPENDIX TV-4, TITLE V CONDITIONS, the following condition applies:

Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall, as of the effective date of the permit, be deemed compliance with any applicable requirements in effect, provided that the source included such applicable requirements in the permit application. Nothing in Rule 62-213.460, F.A.C., or in any permit shall alter or affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program.
[Rule 62-213.460, F.A.C.]

In addition, this permit shield does not currently encompass major or minor source construction permit requirements that are deemed applicable to the source as a result of ongoing litigation. The source shall not be shielded from any such requirements found to be applicable by the court, and in the event that such a finding is made, this will provide a basis for reopening the permit to establish a schedule for complying with these requirements. It is specifically recognized that this exception to the permit shield applies to a determination that major or minor new source construction permit requirements apply to the source. Nothing in the permit has made any specific finding of non-applicability of any PSD, NSPS, or SIP minor source review requirements for any modifications to which these requirements should have applied.

Section III. Emissions Units and Conditions.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-001	Boiler Number 1 - 420 MMBtu/hr (Retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hr **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hr **(to be retired by May 1, 2006)**

Emissions unit number -001 was permanently retired on March 31, 2003. Emissions unit number -002 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 2". It is rated at a maximum heat input of 420 million Btu per hour (MMBtu/hour) when firing natural gas and 320 MMBtu/hour when firing fuel oil. Natural gas is the primary fuel. Emissions unit number -003 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 3". It is rated at a maximum heat input of 550 million Btu per hour (MMBtu/hour) when firing natural gas and/or fuel oil. Natural gas is the primary fuel. Units -002 and -003 are regulated under Acid Rain, Phase II. Units -002 and -003 will be permanently retired by My 1, 2006.

{Permitting notes: These emissions units pre-date PSD regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. Emissions from these boilers are uncontrolled. Unit -002 began commercial operation on June 1, 1949. Unit -003 began commercial operation on September 1, 1952. The generator nameplate rating for unit -002 is 28 megawatts (MW). The generator nameplate rating for unit -003 is 39 MW. Units -002 and -003 share a common stack with units -004 and -005. Stack height = 450 feet, exit diameter = 18.0 feet, exit temperature = 290 °F, actual volumetric flow rate = 802,500 acfm.}

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
-002	420	Natural Gas
	320	No. 2 Fuel Oil
	320	No. 6 Fuel Oil
	320	On-Specification Used Oil
-003	550	Natural Gas
	550	No. 2 Fuel Oil
	550	No. 6 Fuel Oil
	550	On-Specification Used Oil

Note: When a blend of fuel oils and natural gas are fired, the heat input shall be prorated based on the percent heat input of each fuel.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.; and, 0330045-010-AC.]

A.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **A.25.**
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation - Fuels. The fuels that are allowed to be burned in these boilers, in any combination with respect to the proration of heat contents, are natural gas, No. 2 fuel oil, No. 6 fuel oil and on-specification used oil (see Specific Condition **A.35.**).
[Rule 62-213.410, F.A.C.; and, Applicant's requests in Title V permit renewal application received June 22, 2004.]

A.4. Hours of Operation. These emissions units may operate continuously, i.e. 8760 hours/year. For each emissions unit, the permittee shall maintain a daily operations log available for Department inspection that documents the total hours of annual operation, including an account of the hours operated on each of the allowable fuels.
[Rules 62-213.440 and 62-210.200(PTE), F.A.C.; and, Applicant's requests in Title V permit renewal application received June 22, 2004.]

Emission Limitations and Standards

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

A.5. Visible Emissions. Visible emissions shall not exceed 20 percent opacity except for one two-minute period per hour during which opacity shall not exceed 40 percent. Because units -002 and-003 share a common stack with units -004 and -005, visible emissions violations from the stack will be attributed to all five units unless opacity meter results show the specific unit causing the violation.
[Rule 62-296.405(1)(a), F.A.C.; and, AO17-249656, Specific Condition 8.]

A.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

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

{Permitting Note: Load changes may be demonstrated by monitoring megawatt output.}

A.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

{Permitting Note: The averaging time shall correspond to the cumulative sample time, as specified in the reference test method (see Specific Condition **A.18.**).}

A.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

A.9. Sulfur Dioxide - Liquid Fuel. When burning liquid fuel, sulfur dioxide emissions shall not exceed 1.98 pounds per million Btu heat input , as measured by applicable compliance methods.
[Rule 62-296.405(1)(c)1.e., F.A.C.]

A.10. Sulfur Dioxide - Sulfur Content. In order to ensure continuous compliance with the liquid fuel sulfur limit specified in Specific Condition **A.9.**, the liquid fuel sulfur content shall not exceed 1.8 percent, by weight, as measured by applicable test methods.
[Rule 62-213.440, F.A.C.; and, Applicant's Request.]

Excess Emissions

A.11. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

A.12. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

A.13. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

A.14. Sulfur Dioxide. Those emissions units not having an operating flue gas desulfurization device may monitor sulfur dioxide emissions by fuel sampling and analysis according to methods approved by the EPA. **Compliance with the liquid fuel sulfur limit will be verified by performing a daily, as-fired, fuel analysis.** This protocol is allowed because these emissions units do not have operating flue gas desulfurization devices. See Specific Conditions **A.10. and A.20.** of this permit.
[Rule 62-296.405(1)(f)1.b., F.A.C.; and, applicant request.]

Required Tests, Test Methods and Procedures

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

A.15. Annual Tests Required. Except as provided in Specific Conditions **A.28. – 30.**, units -002 and -003 shall conduct annual testing for particulate matter and visible emissions in accordance with the requirements listed below.
[Rule 62-297.310(7)(a)4., F.A.C.]

A.16. Visible Emissions. The test method for visible emissions shall be DEP Method 9 (see Specific Condition **A.17.**), incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.]

A.17. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rules 62-297.310 and 62-297.401, F.A.C.]

A.18. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310, and 62-297.401, F.A.C.]

A.19. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-

297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by this permit, the permittee elected to demonstrate compliance by performing a daily, as-fired, fuel analysis.** See Specific Conditions **A.10. and A.20.**
[Rules 62-213.440, 62-296.405(1)(e)3., 62-297.310 and 62-297.401, F.A.C.]

A.20. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.21. Heat Input. Compliance with the heat input limitations specified in Specific Condition **A.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **B.25.c. & d.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The Acid Rain monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

A.22. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard (see Specific Condition **A.28.**);
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   c. Each NESHAP pollutant, if there is an applicable emission standard.
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

[Rule 62-297.310(7), F.A.C.; and SIP Approved]

Compliance Test Requirements

A.23. Determination of Process Variables.

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

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

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

A.24. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

A.25. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

A.26. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

A.27. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
    a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
    b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the

relationship between a proposed surrogate standard and an existing mass emission limiting standard.

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

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

{Permitting Note: Specific Condition A.18. specifies a minimum sample volume of 30 dry standard cubic feet.}

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

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

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings
		Max. deviation between readings	.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

A.28. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

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

[Rule 62-297.310(7)(a)4., F.A.C.]

A.29. Particulate Matter Testing - Annual. Annual compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s), other tha~~t~~ during startup, for no more than 400 hours per year,; or,
c. only liquid fuel(s), other tha~~t~~ during startup, for no more than 400 hours per year.

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

A.30. Particulate Matter Testing - Permit Renewal. Permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for no more than 400 hours per year; or,
c. only liquid fuel(s) for no more than 400 hours per year.

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

Recordkeeping and Reporting Requirements

A.31. The owner or operator shall maintain daily records of fuel consumption and each analysis that provides the heating value and sulfur content for all fuels fired. These records must be of sufficient detail to determine compliance with the conditions of this permit.
[Rules 62-213.440 and 62-4.070(3), F.A.C.]

A.32. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

A.33. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

A.34. 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 on the results of each such test.
(b) The required test report shall be filed with the Department 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 to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required `and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

Miscellaneous Conditions.

A.35. Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power, not to exceed 10,000 gallons per calendar year in each boiler (units -002 & -003).

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Requirements: For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel. A generator, transporter, processor/re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications.
[40 CFR 279.72(a)]

Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(i) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.
(ii) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater

have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.

(iii) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see Specific Condition **A.20.**).

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
   (1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and
   (2) For each deposit of used oil, results of the analyses as required by the above conditions, or
   (3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above, the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

A.36. Common Conditions. These emissions units are also subject to the conditions in Subsection E. [0330045-005-AC]

Subsection B. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-004	Boiler Number 4 (Substitution Phase I Acid Rain Unit)
-005	Boiler Number 5 (Substitution Phase I Acid Rain Unit)

Emissions unit number -004 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 4". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Emissions unit number -005 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 5". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Both units are Phase I Substitution and Phase II Acid Rain Units.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase I and Phase II. These emissions units pre-date PSD regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from units -004 and -005 are controlled by hot side (Buell Model # Bal. 2x34n333-4-3p) and cold side (Buell Model # 1.1x48k33-1p) electrostatic precipitators. Unit -004 began commercial operation on July 1, 1959. Unit -005 began commercial operation on June 1, 1961. The generator nameplate rating for unit -004 is 93 MW. The generator nameplate rating for unit -005 is 93 MW. Units -004 and -005 share a common stack with units -002 and -003. Stack height = 450 feet, exit diameter = 18.0 feet, exit temperature = 290 °F, actual volumetric flow rate = 802,500 acfm.}

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
-004	1,096.7	Coal
	1,096.7	Natural Gas
	1,096.7	No. 2 Fuel Oil
	1,096.7	On-Specification Used Oil
-005	1,096.7	Coal
	1,096.7	Natural Gas
	1,096.7	No. 2 Fuel Oil
	1,096.7	On-Specification Used Oil

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), 62-214.330 & 62-296.405, F.A.C.; and, permits AC17-2126, AC17-2127 & 0330045-010-AC.]

B.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **B.31.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation.

a. Fuels. The fuels that are allowed to be burned in these boilers are coal, natural gas, new No. 2 fuel oil and/or on-specification used oil (see Specific Condition **B.38.**). Fuel oil is only used for periods of start-up and as needed for flame stabilization. Also, on-site generated "oil contaminated soil" is periodically combusted for energy recovery purposes.

b. Other.
   i. Supplemental injection of "GAM 60" for purposes of maintaining boiler tube temperatures.
   ii. Supplemental injection of sodium carbonate or sodium sulfate at a rate of 440 pounds per hour as necessary to enhance the operation of the particulate control devices on these units

[Rule 62-213.410, F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

B.4. Hours of Operation. These emissions units may operate continuously, i.e. 8760 hours/year. For each emissions unit, the permittee shall maintain a daily operations log available for Department inspection that documents the total hours of annual operation, including an account of the hours operated on each of the allowable fuels.
[Rules 62-213.440 and 62-210.200(PTE), F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

Emission Limitations and Standards

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

{Permitting Note: Unless otherwise specified, the averaging times for Specific Conditions **B.5.-B.10.** are based on the specified averaging time of the applicable test method.}

B.5. Visible Emissions. Visible emissions shall not exceed 40 percent opacity. Because units -004 and -005 share a common stack with units -002 and -003, visible emissions violations from the stack will be attributed to all five units unless opacity meter results show the specific unit causing the violation.
[Rule 62-296.405(1)(a), F.A.C.; and, Secretarial ORDER(s) signed October 18, 1985 & January 3, 1986; and, AO17-211303, Specific Condition 10.]

B.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed for boiler cleaning and load changes, at units which have installed continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

{Permitting Note: Load changes may be demonstrated by monitoring megawatt output.}

B.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

B.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

B.9. Sulfur Dioxide - Solid Fuel. When burning solid fuel, sulfur dioxide emissions shall not exceed 5.90 pounds per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(c)2.c., F.A.C.]

B.10. Sulfur Dioxide - Liquid Fuel. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.40 pounds per million Btu heat input , as measured by applicable compliance methods.
[0330045-010-AC]

B.11. Sulfur Dioxide - Sulfur Content. In order to ensure continuous compliance with the liquid fuel sulfur limit specified in Specific Condition **B.10.**, the liquid fuel sulfur content shall not exceed 2.18 percent, by weight, as measured by applicable test methods.
[Rule 62-213.440, F.A.C.]

Excess Emissions

B.12. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

B.13. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

B.14. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

{Permitting Note: In accordance with the Acid Rain Phase II requirements, the following continuous monitors are installed on these units: SO_2, NO_X, CO_2 and stack gas flow.}

B.15. Continuous Monitors. For these emissions units, the permittee shall calibrate, operate and maintain continuous emissions monitoring systems (CEMS) for monitoring opacity, SO_2 and CO_2.
[Rule 62-296.405(1)(f)1., F.A.C.; and, Permit AO17-211303.]

B.16. Sulfur Dioxide. Those emissions units not having an operating flue gas desulfurization device may monitor sulfur dioxide emissions by fuel sampling and analysis according to methods approved by the EPA. **The permittee elected to satisfy the monitoring requirements using SO_2 continuous emissions monitors.**
[Rule 62-296.405(1)(f)1.b., F.A.C.; and, Applicant request.]

Required Tests, Test Methods and Procedures

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

B.17. Annual Tests Required. Units -004 and -005 shall be tested annually for SO_2 and PM emissions in accordance with the requirements listed below.
[Rule 62-297.310(7)(a)4., F.A.C.]

{Permitting Note: The annual SO_2 test that is required by Rule 62-297.310(7), F.A.C., can be done during the annual RATA as satisfaction of this requirement, provided all other testing requirements specified in the permit are met.}

B.18. Testing While Injecting Additives. The owner or operator shall conduct all emissions tests while injecting additives consistent with normal operating practices approved by the Department.
[Rule 62-213.440, F.A.C.]

B.19. Visible Emissions. The test method for visible emissions shall be DEP Method 9 (see Specific Condition **B.20.**), incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. **The permittee has elected to utilize a transmissometer (opacity meter) for demonstrating compliance with the visible emissions limit.** As long as the transmissometer is calibrated, maintained, and operated in accordance with Performance Specification 1 of 40 CFR 60, Appendix B (see Specific Condition **B.24.**), the annual test for visible emissions is not required.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

{Permitting Note: A transmissometer used to demonstrate compliance should record sufficient data so as to be equivalent to a Method 9 test. Method 9 requires determining an average based on 24 readings at 15-second intervals, thus, a six-minute average. The transmissometers in use at this facility make a permanent recording every six-minutes based on an average of readings taken every 15 seconds. After the 6-minute average is recorded, the individual readings are erased and a new 6-minute average is determined based on the next set of 24 individual readings. This 6-minute block recording is consistent with the requirements of Method 9.}

B.20. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rules 62-297.310 and 62-297.401, F.A.C.]

B.21. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310, and 62-297.401, F.A.C.]

B.22. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-297.310, and 62-297.401, F.A.C.; and, AO17-211303.]

{Permitting Note: The permittee has elected to demonstrate compliance by means of a continuous emissions monitoring system (CEMS). In addition to any other requirements associated with the operation and maintenance of these CEMS (i.e., Acid Rain requirements), operation of the CEMS shall be in accordance with the requirements listed below. The annual calibration RATA associated with these CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the

requirements of Rule 62-297.310, F.A.C., are met (i.e., prior test notification, proper test result submittal, etc.).}

B.23. Continuous SO_2 emission monitoring 24-hour averages are required to demonstrate compliance with the standards of the Department (see Specific Conditions **B.9. - B.11.**). A valid 24-hour average shall consists of no less than 18 hours of valid data capture per calendar day. In the event that valid data capture is interrupted, the permittee shall initiate as-fired fuel sampling to demonstrate compliance with the SO_2 emissions standard. The as-fired fuel sampling shall be initiated no later than 36 hours after the permittee has verified the problem or no later than 36 hours after the end of the affected calendar day. As-fired fuel sampling shall continue until such time as valid data capture is restored. In lieu of as-fired fuel sampling, the permittee may elect to demonstrate SO_2 emissions compliance by the temporary use of a spare SO_2 emissions monitor. The spare, previously calibrated, SO_2 emissions monitor must be installed and collecting data in the same time frame as required above for as-fired fuel sampling.

A quality control (QC) program must be maintained. At a minimum, the QC program must include written procedures which shall describe in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS.
2. Calibration Drift (CD) determination and adjustment of CEMS.
3. Preventative maintenance of CEMS (including spare parts inventory).
4. Data recording, calculations and reporting.
5. Accuracy audit procedures including sampling and analysis methods.
6. Program of corrective action for malfunctioning CEMS.

[Rules 62-213.440, 62-204.800(7)(e)5. and 62-296.405(1)(f)1.b., F.A.C.; and, AO17-211303.]

B.24. Continuous Monitor Performance Specifications. If continuous monitoring systems are required by rule or are elected by the permittee to be used for demonstrating compliance with the standards of the Department, they must be installed, maintained and calibrated, either:

(a) in accordance with the EPA performance specifications listed below. These Performance Specifications are contained in 40 CFR 60, Appendix B, and are adopted by reference in Rule 62-204.800, F.A.C.
   (1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.
   (2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources.
   (3) Performance Specification 3--Specifications and Test Procedures for CO_2 Continuous Emission Monitoring Systems in Stationary Sources. Or,

(b) in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Excess emissions pursuant to Rule 62-210.700, F.A.C., shall be determined using the 40 CFR part 75 CEMS.

[Rule 62-297.520, F.A.C.; 40 CFR 75; and, Applicant request.]

B.25. Fuel Sampling and Analysis. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard in the event that the SO_2 continuous emissions monitor is not able to capture valid data:

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

b. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using ASTM D2013-72 and either ASTM D3177-75 or ASTM D4239-85, or the latest edition, to analyze a representative sample of the blended as-fired pulverized coal.
c. Determine and record the density (using ASTM D 1298-80, or equivalent) and the calorific heat value in Btu per pound (using ASTM D 240-76, or the latest edition) of the fuel oil combusted.
d. Determine and record the calorific heat value in Btu per pound of the blended, as-fired pulverized coal using ASTM D2013-72 and either ASTM D2015-77 or D3286-(latest version), or the latest edition.
e. Record daily the amount of each fuel fired, the density of the fuel oil, the heating value of each fuel fired, and the percent sulfur content, by weight, of each fuel fired.
f. Utilize the information in a., b., c., d. and e., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

B.26. Heat Input. Compliance with the heat input limitations specified in Specific Condition **B.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **B.25.c. & d.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

B.27. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

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

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

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

Compliance Test Requirements

B.28. Determination of Process Variables.

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

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

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

B.29. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to

this permit.
[Rule 62-297.310(6), F.A.C.]

B.30. 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.31. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

B.32. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
   a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
   b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

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

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

{Permitting Note: Specific Condition **B.21.** specifies a minimum sample volume of 30 dry standard cubic feet.}

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

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

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass	+/-2% ref. thermometer or equivalent, or thermometric points
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass	5 degrees F ref. thermometer, NBS calibrated reference and potentiometer
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

Recordkeeping and Reporting Requirements

B.33. The owner or operator shall maintain daily records of all fuels consumed.
[Rules 62-213.440 & 62-4.070(3), F.A.C.]

B.34. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

B.35. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

B.36. A maintenance log of the continuous monitoring systems shall be kept showing the following:
a. Time out of service.
b. Calibration and adjustments.
[Rule 62-213.440, F.A.C.; and, AO17-211303, Specific Condition 8.]

B.37. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department 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 to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.

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

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

Miscellaneous Conditions.

B.38. Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power Company, not to exceed 50,000 gallons per calendar year in each boiler (-004 & -005).

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Requirements: For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel. A generator, transporter, processor/re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications.
[40 CFR 279.72(a)]

Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(i) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.
(ii) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.
(iii) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see Specific Condition **B.25.**).

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
   (1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and
   (2) For each deposit of used oil, results of the analyses as required by the above conditions, or
   (3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

   [40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above and the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

B.39. Compliance Assurance Monitoring. These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C.
[40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

B.40. Common Conditions. These emissions units are also subject to the conditions in Subsection E.
[0330045-005-AC]

Subsection C. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-006	Boiler Number 6 (Phase I Acid Rain Unit)
-007	Boiler Number 7 (Phase I Acid Rain Unit)

Emissions unit number -006 is a Foster Wheeler front wall fired, dry bottom boiler designated as "Boiler Number 6". It is rated at a maximum heat input of 3,704.8 million Btu per hour (MMBtu/hour) when firing pulverized coal and/or natural gas. Emissions unit number -007 is a Foster Wheeler front and rear wall fired, dry bottom boiler designated as "Boiler Number 7". It is rated at a maximum heat input of 6,406.4 million Btu per hour (MMBtu/hour) when firing pulverized coal and/or natural gas. Fuel oil is used as a back-up fuel in both units and for periods of start-up and flame stabilization.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase I. These emissions units pre-date PSD regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. Particulate matter emissions from unit -006 are controlled by a cold side electrostatic precipitator (Wheelabrator Model # HaRDE). Particulate matter emissions from unit -007 are controlled by cold side electrostatic precipitators designed by Alstom Power Inc. NO_X emissions from units -006 are controlled by Foster Wheeler Low NO_X Burners. NO_X emissions from unit -007 are controlled by Foster Wheeler Low NO_X Burners and by an SCR system designed to achieve no less than an 85% reduction in NO_X emissions as measured across the SCR unit inlet and outlet. The designed target ammonia slip level is 5 ppmv based on a 24-hour average. Unit -006 began commercial operation on May 1, 1970. Unit -007 began commercial operation on August 1, 1973. Units -006 and -007 share a common stack. Stack height = 450 feet, exit diameter = 23.2 feet, exit temperature = 320 °F, actual volumetric flow rate = 2,462,700 acfm.}

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
-006	3,704.8	Coal
	3,704.8	Natural Gas
	714.8	No. 2 Fuel Oil
	714.8	On-Specification Used Oil
-007	6,406.4	Coal
	6,406.4	Natural Gas
	1,282	No. 2 Fuel Oil
	1,282	On-Specification Used Oil

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), 62-214.330 & 62-296.405, F.A.C.; and, permits AC17-2126, AC17-2127 & 0330045-010-AC.]

C.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.39.**
[Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation.

a. Fuels. The fuels that are allowed to be burned in these boilers are coal, natural gas, new No. 2 fuel oil and/or on-specification used oil (see Specific Condition **C.48.**). Fuel oil is only used for periods of start-up and as needed for flame stabilization. Also, on-site generated "oil contaminated soil" is periodically combusted for energy recovery purposes.

b. Other.
   1. Supplemental injection of ammonia at a rate of 25 to 40 pounds per hour.
   2. Supplemental injection of sulfur trioxide at a rate of 4 to 20 ppm.
   3. Supplemental injection of "GAM 60" for purposes of maintaining boiler tube temperatures.

[Rule 62-213.410, F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

C.4. Hours of Operation. These emissions units may operate continuously, i.e. 8760 hours/year. For each emissions unit, the permittee shall maintain a daily operations log available for Department inspection that documents the total hours of annual operation, including an account of the hours operated on each of the allowable fuels.
[Rules 62-213.440 and 62-210.200(PTE), F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

Emission Limitations and Standards

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

{Permitting Note: Unless otherwise specified, the averaging times for Specific Conditions **C.5.-C.12.** are based on the specified averaging time of the applicable test method.}

C.5. Visible Emissions. Visible emissions from unit -006 shall not exceed 40 percent opacity. Visible emissions from unit -007 shall not exceed 20% based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27%. Because units -006 and -007 share a common stack, visible emissions violations from the stack will be attributed to both units unless opacity meter results show the specific unit causing the violation.
[Rule 62-296.405(1)(a), F.A.C.; and, Secretarial ORDER(s) signed May 12, 1988 & June 24, 1988; and, permits AC17-2234016, Specific Condition 14, AO17- 171806, Specific Condition 23 & 0330045-005-AC.]

C.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed for boiler cleaning and load changes, at units which have installed continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

{Permitting Note: Load changes may be demonstrated by monitoring megawatt output.}

C.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods. Particulate matter emissions from unit 6 shall not exceed 1,475 tons per year.
[Rule 62-296.405(1)(b), F.A.C.; and, AC17-234016.]

C.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

C.9. Sulfur Dioxide - Solid Fuel. When burning solid fuel, sulfur dioxide emissions shall not exceed 2.40 pounds per million Btu heat input, as measured by applicable compliance methods. When burning solid fuel, sulfur dioxide emissions from unit 6 shall not exceed 38,945 tons per year.
[Rule 62-296.405(1)(c)2.c., F.A.C.; and, 0330045-008-AC.]

C.10. Sulfur Dioxide - Liquid Fuel. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.40 pounds per million Btu heat input , as measured by applicable compliance methods.
[0330045-010-AC]

C.11. Sulfur Dioxide - Sulfur Content. In order to ensure continuous compliance with the liquid fuel sulfur limit specified in Specific Condition **C.10.**, the liquid fuel sulfur content shall not exceed 2.18 percent, by weight, as measured by applicable test methods.
[Rule 62-213.440, F.A.C.]

C.12. Nitrogen Oxides.

a. (Interim). Prior to implementing the required NO_X control strategy for Units -004, -005 and -006, the NO_X emissions from Unit -007 shall not exceed 0.15 lb/MMBtu of heat input based on a 30-day rolling average when the SCR system is operational with a catalyst temperature of at least 600° F. The permittee shall demonstrate compliance with data collected from the certified CEMS.

b. Permanent. After the required NO_X control strategy is implemented for Units -004, -005, and -006, the plant-wide NO_X standard specified in Subsection E. shall supersede this interim standard.
[0330045-005-AC]

Excess Emissions

C.13. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

C.14. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

C.15. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

SCR Operation

C.16. Selective Catalytic Reduction (SCR) System: The permittee shall operate and maintain an SCR system for Unit -007 to reduce emissions of nitrogen oxides (NO_X) as described in the application, approved drawings, plans, and other documents on file with the Department. The SCR system shall be designed to achieve no less than an 85% reduction in NO_X emissions as measured across the SCR unit inlet and outlet. The designed target ammonia slip level is 5 ppmv based on a 24-hour average. The storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[0330045-005-AC]

SCR Bypass Operation

C.17. SCR Bypass, Startup/Shutdown: During Unit -007 startup and shutdown, the SCR system may be bypassed in accordance with manufacturer's recommended procedures to allow for controlled catalyst heating and cooling. During startup, the SCR system shall be on line and functioning when the minimum operating temperature of the catalyst is achieved (≥ 600° F). During shutdown, the SCR system may be removed from service when the catalyst temperature drops below 600° F.
[Design; Rule 62-210.700, F.A.C. ; and, 0330045-005-AC.]

C.18. SCR Bypass, Catalyst Maintenance and Repair: The permittee may bypass the SCR system to perform catalyst maintenance and repair for up to 15 days per year during the non-ozone season. During such allowable bypass periods, the uncontrolled NO_X emissions from Unit -007 shall not exceed 0.35 lb/MMBtu based on a 24-hour average. The daily NO_X emission rates for these periods may be excluded from the plant-wide 30-day NO_X standard specified in Specific Condition **E.2.** The permittee shall notify the Compliance Authority in advance of the purpose of the SCR bypass, the expected dates of SCR bypass, and the expected duration of SCR bypass.
[Rules 62-210.700 and 62-4.070(3), F.A.C.; and, 0330045-005-AC.]

{Permitting Note: The ozone season is defined as May 1st through September 15th.}

Monitoring of Operations

{Permitting Note: In accordance with the Acid Rain Phase II requirements, the following continuous monitors are installed on these units: SO_2, NO_X, CO_2 and stack gas flow.}

C.19. Continuous Monitors. For these emissions units, the permittee shall calibrate, operate and maintain continuous monitoring systems for monitoring opacity, SO_2, NO_X and CO_2.
[Rule 62-296.405(1)(f)1., F.A.C.; and, Permits AC17-234016, AO17-171806 & 0330045-005-AC.]

C.20. COMS. The permittee shall install, calibrate, operate and maintain a continuous opacity monitoring system (COMS) to demonstrate compliance with the stack opacity standard. The COMS shall monitor and record data during all periods of Unit -007 operation including startup, shutdown, malfunction or emergency conditions, but not including continuous monitoring system breakdowns, repairs, or calibration checks.
[0330045-005-AC]

{Permitting Note: The existing COMS required by the Acid Rain program satisfies this requirement.}

C.21. NO_X CEMS: To demonstrate compliance with the emissions standards, the permittee shall install, calibrate, operate and maintain a continuous emissions monitoring system (CEMS) to continuously monitor and record the emissions of nitrogen oxides and an appropriate diluent gas (carbon dioxide or oxygen). The CEMS shall monitor and record data during all periods of Unit -007 operation including startup, shutdown, malfunction or emergency conditions, but not including continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments. For each calendar quarter, monitor availability shall be 95% or greater. If unable to achieve this level, the permittee shall submit a report identifying the problems in achieving 95% monitor availability and a plan of corrective actions. The permittee shall implement the reported corrective actions within the next calendar quarter.
[0330045-005-AC]

{Permitting Note: The existing NO_X CEMS required by the Acid Rain program satisfies this requirement.}

C.22. Sulfur Dioxide. Those emissions units not having an operating flue gas desulfurization device may monitor sulfur dioxide emissions by fuel sampling and analysis according to methods approved by the EPA. **The permittee elected to satisfy the monitoring requirements using SO_2 continuous emissions monitors.**
[Rule 62-296.405(1)(f)1.b., F.A.C.; Permits AC17-234016 & AO17-171806; and, Applicant request.]

Required Tests, Test Methods and Procedures

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

C.23. Annual Tests Required. Units -006 and -007 shall be tested annually for NO_X, SO_2, PM and ammonia slip emissions in accordance with the requirements listed below.
[Rule 62-297.310(7)(a)4., F.A.C.; and, 0330045-005-AC]

{Permitting Note: The annual SO_2 test that is required by Rule 62-297.310(7), F.A.C., can be done during the annual RATA as satisfaction of this requirement, provided all other testing requirements specified in the permit are met.}

C.24. Testing While Injecting Additives. The owner or operator shall conduct all emissions tests while injecting additives consistent with normal operating practices approved by the Department.
[Rule 62-213.440, F.A.C.]

C.25. Visible Emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. **The permittee has elected to utilize a transmissometer (opacity meter) for demonstrating compliance with the visible emissions limit**. As long as the transmissometer is calibrated, maintained, and operated in accordance with Performance Specification 1 of 40 CFR 60, Appendix B (see Specific Condition **C.32.**), the annual test for visible emissions is not required.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

{Permitting Note: A transmissometer used to demonstrate compliance should record sufficient data so as to be equivalent to a Method 9 test. Method 9 requires determining an average based on 24 readings at 15-second intervals, thus, a six-minute average. The transmissometers in use at this facility make a permanent recording every six-minutes based on an average of readings taken every 15 seconds. After the 6-minute average is recorded, the individual readings are erased and a new 6-minute average is determined based on the next set of 24 individual readings. This 6-minute block recording is consistent with the requirements of Method 9.}

C.26. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rules 62-297.310 and 62-297.401, F.A.C.]

C.27. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be

30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310, and 62-297.401, F.A.C.]

C.28. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards.
[Rules 62-213.440, 62-296.405(1)(e)3. 62-297.310 and 62-297.401, F.A.C.; and, Permits AC17-234016 and AO17-171806.]

{Permitting Note: The permittee has elected to demonstrate compliance by means of a continuous emissions monitoring system (CEMS). In addition to any other requirements associated with the operation and maintenance of these CEMS (i.e., Acid Rain requirements), operation of the CEMS shall be in accordance with the requirements listed below. The annual calibration RATA associated with these CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the requirements of Rule 62-297.310, F.A.C., are met (i.e., prior test notification, proper test result submittal, etc.).}

C.29. Continuous SO_2 emission monitoring 24-hour averages are required to demonstrate compliance with the standards of the Department (see Specific Conditions **C.9. - C.11.**). A valid 24-hour average shall consist of no less than 18 hours of valid data capture per calendar day. In the event that valid data capture is not available, the permittee shall initiate as-fired fuel sampling to demonstrate compliance with the SO_2 emissions standard. The as-fired fuel sampling shall be initiated no later than 36 hours after the permittee has verified the problem or no later than 36 hours after the end of the affected calendar day. Fuel sampling shall continue until such time as the valid data capture is restored. In lieu of as-fired fuel sampling the permittee may elect to demonstrate SO_2 emissions compliance by the temporary use of a spare SO_2 emissions monitor. The spare SO_2 emissions monitor must be installed and collecting data in the same time frame as required above for as-fired fuel sampling.

Maintain a QC program. At a minimum, the QC program must include written procedures which shall describe in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS.
2. Calibration Drift (CD) determination and adjustment of CEMS.
3. Preventative maintenance of CEMS (including spare parts inventory).
4. Data recording, calculations and reporting.
5. Accuracy audit procedures including sampling-and analysis methods.
6. Program of corrective action for malfunctioning CEMS.

[Rules 62-213.440, 62-204.800(7)(e)5., and 62-296.405(1)(f)1.b., F.A.C.; and, Permits AC17-234016 and AO17-171806.]

C.30. Nitrogen Oxides, Compliance Tests. During each federal fiscal year (October 1st to September 30th), the permittee shall conduct tests to demonstrate compliance with the emission limits contained in Specific Condition C.12. and with the design specification to achieve no less than an 85% reduction in the nitrogen oxide emission rate. The permittee shall concurrently test the SCR inlet and SCR outlet in accordance with EPA Method 7E as adopted by reference in Rule 62-204.800, F.A.C. Data collected during the annual NO_X RATA testing may be used to represent NO_X emissions at the SCR outlet. Alternatively, the permittee may submit data collected from the NO_X rate process monitors at the SCR inlet and SCR outlet, which are part of the ammonia injection system. The data shall be collected for at least three consecutive hours.
[Rules 62-4.070(3) & 62-297.310(7), F.A.C.; and, 0330045-005-AC.]

C.31. Ammonia Slip, Performance Tests. During each federal fiscal year, the permittee shall conduct tests to determine the ammonia slip rate in accordance with EPA Method CTM-027 or other methods approved by EPA. If tests show ammonia slip emissions are greater than the design target level specified in Specific Condition **C.16.** of this subsection, the permittee shall take corrective actions such as repair, addition of catalyst, replacement of catalyst, etc.
[Rules 62-4.070(3) & 62-297.310(7), F.A.C.; and, 0330045-005-AC.]

C.32. Continuous Monitor Performance Specifications. If continuous monitoring systems are required by rule or are elected by the permittee to be used for demonstrating compliance with the standards of the Department, they must be installed, maintained and calibrated, either:

(a) in accordance with the EPA performance specifications listed below. These Performance Specifications are contained in 40 CFR 60, Appendix B, and are adopted by reference in Rule 62-204.800, F.A.C.
  (1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.
  (2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources.
  (3) Performance Specification 3--Specifications and Test Procedures for CO_2 Continuous Emission Monitoring Systems in Stationary Sources. Or,

(b) in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Excess emissions pursuant to Rule 62-210.700, F.A.C., shall be determined using the 40 CFR part 75 CEMS.

[Rule 62-297.520, F.A.C.; 40 CFR 75; and, Applicant request.]

C.33. Fuel Sampling and Analysis. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard in the event that the SO_2 continuous emissions monitor is not able to capture valid data:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, to analyze a representative sample of the blended fuel following each fuel delivery.
b. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using ASTM D2013-72 and either ASTM D3177-75 or ASTM D4239-85, or the latest edition, to analyze a representative sample of the blended as-fired pulverized coal.
c. Determine and record the density (using ASTM D 1298-80, or equivalent) and the calorific heat value in Btu per pound (using ASTM D 240-76, or the latest edition) of the fuel oil combusted.

d. Determine and record the calorific heat value in Btu per pound of the blended, as-fired pulverized coal using ASTM D2013-72 and either ASTM D2015-77 or D3286-(latest version), or the latest edition.
e. Record daily the amount of each fuel fired, the density of the fuel oil, the heating value of each fuel fired, and the percent sulfur content, by weight, of each fuel fired.
f. Utilize the information in a., b., c., d. and e., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

C.34. Determination of Compliance with Permitted Capacity. Compliance with the heat input limitations specified in Specific Condition **C.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **C.33.c. & d.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

C.35. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

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

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

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

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

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

Compliance Test Requirements

C.36. Determination of Process Variables.

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

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

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

C.37. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.

[Rule 62-297.310(6), F.A.C.]

C.38. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured

provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

C.39. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

C.40. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
    a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
    b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
    c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
{Permitting Note: Specific Condition C.21. specifies a minimum sample volume of 30 dry standard cubic feet.}

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass	+/-2% ref. thermometer or equivalent, or thermometric points
Bimetallic thermometer	Quarterly	Calib. liq. in	5 degrees F glass thermometer
Thermocouple	Annually	ASTM Hg in glass	5 degrees F ref. thermometer, NBS calibrated reference and potentiometer
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

Recordkeeping and Reporting Requirements

C.41. The owner or operator shall maintain daily records of all fuels consumed.
[Rules 62-213.440 and 62-4.070(3), F.A.C.]

C.42. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

C.43. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

C.44. A maintenance log of the continuous monitoring systems shall be kept showing the following:
a. Time out of service.
b. Calibration and adjustments.

[Rule 62-213.440, F.A.C.; and, Permits AC17-234016 & AO17-171806.]

C.45. 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 on the results of each such test.
(b) The required test report shall be filed with the Department 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 to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.

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

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

C.46. Test Reports. The permittee shall prepare and submit reports for all required tests in accordance with the provisions of Rule 62-297.310(8), F.A.C. For each required test run, the report shall indicate the actual heat input rate (MMBtu/hour), the NO_X emission rate (lb/MMBtu) as recorded by the CEMS, the ammonia injection rate (lb/hour), and the ammonia slip rate. The report shall also include copies of the continuous monitoring records for opacity and NO_X emissions.
[Rule 62-297.310(8), F.A.C.; and, 0330045-005-AC.]

C.47. Quarterly Report.

a. NO_X Summary. For each calendar day during the reporting quarter, the permittee shall report the following information related to the NO_X CEMS for Unit -007:
   1. Hours of operation for Unit -007;
   2. Daily average NO_X emission rate, lb/MMBtu;
   3. 30-day average NO_X emission rate, lb/MMBtu; and
   4. Whether or not the day included a startup, shutdown, malfunction or bypass of the SCR.

   Identify the "F" factor used for any calculations, the method of determination, and type of fuel combusted. For each day that CEMS data was not obtained for at least 18 hours of Unit 7 operation, provide a justification for not obtaining sufficient data and describe the corrective actions taken to prevent this in the future. Identify any emissions data excluded from the calculation of emission rates due to startup, shutdown, or malfunction.

b. Opacity Summary. For each calendar day during the reporting quarter, the permittee shall report each 6-minute period in excess of the opacity standard.
c. Gas Sampling Grid (GSG). The permittee shall summarize any tests using the GSG that were conducted during the calendar quarter.

Each quarterly report is due within 30 days of the calendar quarter being reported. [0330045-005-AC]

Miscellaneous Conditions.

C.48. Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power Company, not to exceed 50,000 gallons per calendar year in each boiler (-006 & -007).

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Requirements: For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel. A generator, transporter, processor/ re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications.
[40 CFR 279.72(a)]

Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(i) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.

(ii) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.

(iii) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see Specific Condition **C.25.**).

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:

(1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and

(2) For each deposit of used oil, results of the analyses as required by the above conditions, or

(3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above and the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

C.49. Compliance Assurance Monitoring. These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C.
[40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

C.50. Common Conditions. These emissions units are also subject to the conditions in Subsection E.
[0330045-005-AC]

Subsection D. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-008	Fly Ash Storage Silos (2)

This emissions unit consists of two Fly Ash Storage Silos. The fly ash collection systems from the precipitators on boilers numbers 4, 5, 6 & 7 to the three transfer tanks are totally enclosed (i.e. no emission points). Three blowers pneumatically convey dry fly ash to 2 silos at a maximum solids rate of 150 tons per hour to either silo or to both. The majority of the solids (99.4%) settles by gravity upon entering the silo and the residual particulates are controlled by a baghouse on each silo. Each baghouse is a Pulse Jet Fabric Filter - model #100 - WMWC - 420 (IIG) manufactured by Flex-Kleen. Dry fly ash will be transported off-site in closed tanker trucks (approximately 20% sold annually) or conditioned fly ash (12-15% water added) will be transported to an approved landfill area on-site.

{Permitting notes: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required, and Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards. There is one baghouse on each silo. Each silo has two vents. Stack height = 124.5 feet, exit dimensions = 18" x 24" rectangle, exit temperature = 100 °F, actual volumetric flow rate = 5,452 acfm per vent, velocity = 30 feet per second. The two silos were built between October 27, 1981 and June 1, 1983.}

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

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum operating rate is as follows:

Unit No.	Operating Rate
-008	150 Tons Per Hour of Fly Ash Transported to Either or Both Silos

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AC17-47675.]

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

D.3. Hours of Operation. Each fly ash storage silo may operate continuously, i.e. 8,760 hours per year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

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

D.4. Visible Emissions. Visible emissions from each baghouse vent (2 on each baghouse) shall be less than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AC17-47675.]

Excess Emissions

D.5. Excess emissions from this emissions unit resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

D.6. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Required Tests, Test Methods and Procedures

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

D.7. Annual Tests Required. Unit -008 must be tested annually for visible emissions in accordance with the requirements listed below.

D.8. Visible emissions. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

D.9. **Not federally enforceable.** Operating Rate During Testing. Compliance shall be demonstrated at an operating rate which typifies normal operation of the fly ash system. This operating rate may be lower than the maximum allowable operating rate. Should the Department feel that test results do not provide reasonable assurance that the source is capable of compliance at the permitted maximum operating rate, the Department may request that a visible emissions test be conducted at a higher operating rate up to the maximum allowable operating rate.
[January 16, 1984 letter modifying permit AO17-70422, Specific Condition 15.]

D.10. Applicable Test Procedures.

(a) Required Sampling Time.

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

[Rule 62-297.310(4)(a)2., F.A.C.]

D.11. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
    a. Did not operate; or
    b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
    a. Visible emissions, if there is an applicable standard;
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

[Rule 62-297.310(7), F.A.C.; and, SIP Approved.]

Recordkeeping and Reporting Requirements

D.12. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

D.13. Test Reports.

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

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

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

Subsection E. Common Conditions. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-001	Boiler Number 1 - 420 MMBtu/hour (retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hour **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hour **(to be retired by May 1, 2006)**
-004	Boiler Number 4 - 1,096.7 MMBtu/hour
-005	Boiler Number 5 - 1,096.7 MMBtu/hour
-006	Boiler Number 6 - 3,704.8 MMBtu/hour
-007	Boiler Number 7 - 6,406.4 MMBtu/hour

{Permitting Note: August 28, 2002, Gulf Power Company and the Florida Department of Environmental Protection entered into an agreement titles, "Agreement for the Purpose of Ensuring Compliance with the Ozone Ambient Air Quality Standards". This agreement is the basis for the following permit conditions.}

REQUIREMENTS OF THE AGREEMENT

E.1. Supplemental Conditions. The conditions of this section supplement all other valid air construction and operation permits for these units. These conditions are in addition to all other applicable permit conditions and regulations.
[Rule 62-4.070(3), F.A.C.; and, 0330045-005-AC]

E.2. Plant-Wide NO_X Limit. Emissions of nitrogen oxides (NO_X) from the combined operation of Units -004, -005, -006, and -007 shall not exceed 0.2 lb/MMBtu heat input based on a 30-day rolling average except for periods when Unit -007 is shutdown. The plant-wide daily NO_X emission rate shall be determined by the following equation:

$$\text{Plant-Wide Daily MMBtu-Weighted } NO_X \text{ Emission Rate} = \frac{\sum_{\text{Units 4, 5, 6, 7}} [(\text{Unit \# daily MMBtu}) \times (\text{Unit \# daily } NO_X \text{ CEMS Rate})]}{\sum_{\text{Units 4, 5, 6, 7}} (\text{Unit \# daily MMBtu})}$$

The "Unit # daily MMBtu" shall be determined by the daily as-burned fuel analysis and the fuel fired for each unit. The "Unit # daily NO_X CEMS Rate" shall be determined by the daily average of NO_X CEMS data for each unit and reported in terms of "lb/MMBtu heat input". The plant-wide daily NO_X emissions rate shall be determined each day regardless of the operating status for Unit -007. The plant-wide 30-day rolling NO_X average shall be determined for each 30 sequential Unit -007 operating days, which need not be consecutive. A Unit -007 operating day means any calendar day that Unit -007 operates a minimum of 18 hours. The Unit -007 daily NO_X CEMS rate may consist of less than 18 hours of data if this is due to CEMS malfunction or invalid CEMS data. When the catalyst temperature is below 600° F during a startup or shutdown, NO_X emissions data collected during such periods may be excluded from the daily NO_X average. In accordance with Specific Condition **C.18.**, NO_X emissions data collected during SCR bypass during the non-ozone season may be excluded from the daily NO_X average. The plant-wide NO_X emission standard shall be achieved by utilizing the SCR system for Unit -007 and implementing the selected NO_X control strategy for Units -004, -005, and -006. The effective date for the plant-wide NO_X emission standard is:

a. The startup date of the selected additional NO_X reduction project, (excluding an SCR project for Unit -006), but no later than May 1, 2006; or

b. The startup date of the SCR project for Unit -006, but no later than December 31, 2007.

For purposes of this condition, "startup date" shall mean the date that the permittee demonstrates initial compliance with the terms of the required air construction permit (or other Department approval) that authorized implementation of the additional NO_X reduction project. [Paragraphs 2, 3 and Exhibit B of the Agreement]
[0330045-005-AC]

E.3. NO<u></u>$_X$ CEMS. To demonstrate compliance with the plant-wide NO_X emissions standard, the permittee shall install, calibrate, operate and maintain continuous emissions monitoring systems (CEMS) to continuously monitor and record the emissions of nitrogen oxides and an appropriate diluent gas (carbon dioxide or oxygen) from Units -004, -005, -006, and -007.
[Exhibit B of the Agreement; and, 0330045-005-AC]

{Permitting Note: The existing NO_X CEMS required by the Acid Rain program satisfy this requirement.}

E.4. Quarterly Report. For each calendar day during the reporting quarter, the permittee shall report the following information related to the NO_X CEMS for Unit -007:

- Daily NO_X emission rate for each boiler, lb/MMBtu;
- Daily heat input rate for each boiler, MMBtu/day;
- 30-day plant-wide NO_X emissions rate, lb/MMBtu;
- Identify whether Unit -007 operated less than 18 hours;
- Identify the occurrence of a Unit -007 startup or shutdown; and
- Identify operation of Unit -007 with SCR bypass for catalyst maintenance or repair and the duration of bypass (hours).

Identify the "F" factor used for any calculations, the method of determination, and type of fuel combusted. For each day that CEMS data was not obtained for at least 18 hours of Unit -007 operation, provide a justification for not obtaining sufficient data and describe the corrective actions taken to prevent this in the future. Identify any emissions data excluded from the calculation of emission rates due to startup, shutdown, or malfunction.
[0330045-005-AC]

{Permitting Notes: To achieve the plant-wide NO_X standard for the Crist Plant, Gulf Power Company will take the following additional actions.}

65 Unit Retirements: The Agreement requires the retirement of Unit -001 within 120 days of receiving a final order from the Public Service Commission that authorizes the recovery of costs associated with the pollution control equipment incurred pursuant to the Agreement though the Environmental Cost Recovery Clause. **(Unit -001 was retired on March 31, 2003.)** A final order is one that is no longer subject to review or appeal by a court of competent jurisdiction. The Agreement also requires the retirement of Units -002 and -003 on or before May 1, 2006.

[Paragraph 4 of the Agreement]

E6 Additional NO_X Reduction Projects: The Agreement requires Gulf Power Company to conduct a variety of engineering studies to determine the feasibility of NO_X reduction technologies for one or more of the three remaining coal-fired units (Units -004, -005, and -006). The studies and related unit-specific demonstration projects may include (but are not limited to) SCR, selective non-catalytic reduction (SNCR) technology, over-fired air (OFA) technology, natural gas re-burn technology, selective use of biomass fuel, etc. The studies must be complete by May 1, 2005. Before implementing any NO_X reduction technology or combination of technologies, Gulf Power Company must obtain written concurrence from the Department that the use thereof is reasonable and necessary to achieve the overall plant-wide NO_X emission standard. If a NO_X reduction technology or a combination of technologies other than an SCR project for Unit 6 is identified as appropriate, Gulf Power Company will implement the technology or combination of technologies on one or more of the three remaining coal-fired units by May 1, 2006. If an SCR project for Unit -006 is identified as the appropriate NO_X reduction technology, Gulf Power Company will implement, begin and continue operating the SCR system by December 31, 2007.
[Paragraph 2 of the Agreement]}

Section IV. Acid Rain Part.

Operated by: Gulf Power Company
ORIS Code: 641

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

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

E.U. ID No.	Brief Description
	(retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hour **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hour **(to be retired by May 1, 2006)**
-004	Boiler Number 4 - 1,096.7 MMBtu/hour
-005	Boiler Number 5 - 1,096.7 MMBtu/hour
-006	Boiler Number 6 - 3,704.8 MMBtu/hour
-007	Boiler Number 7 - 6,406.4 MMBtu/hour

A.1. The Phase II permit applications, the Phase II NO_X compliance plans and the Phase II NO_X averaging plans submitted for this facility, as approved by the Department, are a part of this permit (included as Attachments). The owners and operators of these Phase II acid rain units must comply with the standard requirements and special provisions set forth in the applications listed below:

a. DEP Form No. 62-210.900(1)(a), F.A.C., Signed 6/1/04.
b. DEP Form No. 62-210.900(1)(a)4., F.A.C., Signed 6/1/04.
c. DEP Form No. 62-210.900(1)(a)5., F.A.C., Signed 11/18/03.

[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 #	EPA ID	Year	2004	2005	2006	2007	2008
-002	**ID No. 02 2**	**SO_2 allowances, under Table 2 or 3 of 40 CFR 73**	3*	3*	3*	3*	3*
-003	**ID No. 03 3**	**SO_2 allowances, under Table 2 or 3 of 40 CFR 73**	4*	4*	4*	4*	4*

E.U. ID #	EPA ID	Year	2004	2005	2006	2007	2008
-004	**ID No. 04 4**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	2467*	2467*	2467*	2467*	2467*
		NO_X limit	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.52** lb/MMBtu. In addition, this unit shall not have an annual heat input **greater than 5,591,320** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				
-005	**ID No. 05 5**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	2430*	2430*	2430*	2430*	2430*
		NO_X limit	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.60** lb/MMBtu. In addition, this unit shall not have an annual heat input **greater than 5,479,586** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				
-006	**ID No. 06 6**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	8396*	8396*	8396*	8396*	8396*

E.U. ID #	EPA ID	Year	2004	2005	2006	2007	2008
-006 (cont')		**NO_X limit**	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.45** lb/MMBtu. In addition, this unit shall not have an annual heat input **less than 21,086,630** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				
-007	**ID No. 07 7**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	12522*	12522*	12522*	12522*	12522*
		NO_X limit	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.45** lb/MMBtu. In addition, this unit shall not have an annual heat input **less than 34,569,955** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				

Units for different purposes.

* 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, 3, or 4 of 40 CFR 73.

Additional Requirements

1. Under the plan (NO_X Phase II averaging plan), the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

2. In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only after the Alabama Department of Environmental Management, the Jefferson County (Alabama) Department

of Health, the Georgia Department of Natural Resources and the Mississippi Department of Environmental Quality, have also approved this averaging plan.

3. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

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)1., 2. & 3., 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.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Where an applicable requirement of the Act is more stringent than applicable 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, F.A.C., Definitions – Applicable Requirements.]

A.6. Comments, notes, and justifications: The Designated Representative has changed from Frederick Kuester to G. Edison Holland, Jr. to Robert G. Moore to Bill M. Guthrie to Charles D. McCrary.

The alternative designated representatives have been changed to include Robert G. Moore and James O. Vick.

Reporting Requirements

A.7. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-4, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

A.8. Demonstration of Compliance With the Phase II NO_X Averaging Plan. The Designated Representative shall provide a copy of the demonstration of compliance, prepared in accordance with 40 CFR 76.11(d), to the Department within 60 (sixty) days after the end of the calendar year.
[Rule 62-213.440, F.A.C.]

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

{Permitting note: The U.S. EPA issues Acid Rain Phase I permits.}

The emissions unit(s) listed below are regulated under Acid Rain Part, Phase I

E.U. ID No.	Brief Description
-004	Boiler Number 4 – 1,096.7 MMBtu/hour (Substitution for Unit -007)
-005	Boiler Number 5 – 1,096.7 MMBtu/hour (Substitution for Unit -007)
-006	Boiler Number 6 – 3,704.8 MMBtu/hour
-007	Boiler Number 7 – 6,406.4 MMBtu/hour

B.1. The Phase I permits, issued by the U.S. EPA, are attached to this permit. The owners and operators of these Phase I acid rain units must comply with the standard requirements and special provisions set forth in the Phase I permits issued December 27, 1994.
[Chapter 62-213, F.A.C.]

B.2. Comments, notes, and justifications: None.

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

Gulf Power Company
Crist Electric Generating Plant

DRAFT Permit No.: 0330045-009-AV
Facility ID No.: 0330045

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

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

	State Registration Number	Contents	Size (Gallons)
1.	1	#2 Diesel – Tractor Fuel	20,000
2.	3	#2 Diesel – Lighter Oil	100,000
3.	4	#2 Diesel – Lighter Oil	100,000
4.	5	#6 Bunker "C"	1,387,000
5.	6	#6 Bunker "C"	1,387,000
6.	7	#6 Bunker "C"	1,387,000
7.	8	Used Oil	15,000
8.	9	Lube Oil	7,000
9.	10	Lube Oil	7,000
10.	11	Waste Oil	12,000
11.	12	Lube Oil	7,000
12.	13	Lube Oil	4,000
13.	14	Lube Oil	4,000
14.	15	Lube Oil	3,000
15.	16	Sulfuric Acid	4,000
16.	17	Sulfuric Acid	6,000
17.	2R1	Gasoline	2,000
18.	--	Used Oil	300

Miscellaneous

19. Fire Safety Equipment
20. Vacuum Pumps
21. Laboratory Equipment
22. Welding Equipment
23. Gulf Power Company Generated Non-hazardous Boiler Chemical Cleaning Wastes
(Not to exceed 50 gallons per minute)

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

Gulf Power Company
Crist Electric Generating Plant

DRAFT Permit No.: 0330045-009-AV
Facility ID No.: 0330045

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

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

E.U. ID No.	Brief Description of Emissions Units and/or Activity
-009	Material Handling of Coal and Ash
-010	Fugitive PM Sources – On-site Vehicles
-011	General Purpose Internal Combustion Engines
-012	Cooling Towers (3)
-013	Fugitive PM Sources – Sandblasting Operations

-009 Material Handling of Coal and Ash. Fugitive PM emissions generated from the transfer and handling of coal and ash. SCC: 3-05-101-03.

-010 Fugitive PM Sources. Fugitive PM emissions generated by haul trucks and other on-site vehicles. SCC: 3-05-101-50.

-011 General Purpose Internal Combustion Engines. Located for use at this source are miscellaneous internal combustion engines used to operate the following: welders, compressors, generators, water pumps, sweepers, and other auxiliary equipment.

-012 Cooling Towers. SCC: 3-90-900-04

-013 Fugitive PM Sources. Fugitive PM emissions generated by sandblasting operations. SCC: 3-05-101-99.

Appendix H-1, Permit History/ID Number Changes

(For Tracking Purposes Only)

Gulf Power Company | **DRAFT Permit No.**: 0330045-009-AV
Crist Electric Generating Plant | **Facility ID No.:** 0330045

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Extended Date [2, 3]	Revised Date(s)
-001	Crist Unit #1	AO17-249656	5/19/94	1/15/96	8/14/96	
-002	Crist Unit #2	AO17-249656	5/19/94	1/15/96	8/14/96	
-003	Crist Unit #3	AO17-249656	5/19/94	1/15/96	8/14/96	
-004	Crist Unit #4	AO17-211303	4/17/92	4/1/97		
		Secretarial ORDER [1]	1/3/86			
		AC17-2126	10/15/75	3/1/77		
-005	Power Boiler No. 5	AO17-211303	4/17/92	4/1/97		
		Secretarial ORDER [1]	10/18/85			
		AC17-2127	10/15/75	3/1/77		
-006	Power Boiler No. 6	AC17-234016	10/7/93	12/1/94		
		AO17-171809	6/6/90	9/2/95	8/14/96	
		Secretarial ORDER [1]	5/12/88			
-007	Crist No. 7	AO17-171806	6/6/90	9/2/95	8/14/96	
		Secretarial ORDER [1]	6/24/88			
-008	Fly Ash Storage Silos (2)	AO17-234356	7/30/93	7/1/98		
		AC17-47675	10/27/81	2/1/83	6/1/83	
All	Initial Title V permit	0330045-001-AV	1/1/00	12/31/04		
-004, -055	Biomass project	0330045-004-AC	12/9/02	10/4/03		
-007	Addition of ESP and SCR	0330045-005-AC	3/3/03	12/1/05		
All	Ambient limit on SO_2	0330045-008-AC	5/18/04	-----		
All	Title V permit Renewal	0330045-009-AV	1/1/05	12/31/09		
All	Revision to SO_2 limit	0330045-010-AC				

1 Secretarial ORDER issued to relax semi-annual PM testing requirement to annual. Previous ORDERs had been issued to relax the Rule required quarterly testing requirement to semi-annual.
2 AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
3 AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.

{Rule 62-213.420(1)(b)2., F.A.C., allows Title V Sources to operate under existing valid permits that were in effect at the time of application until the Title V permit becomes effective}

Referenced Attachments

Phase I Acid Rain Permits

Phase II Acid Rain Application/Compliance Plan

Phase II Acid Rain NO_X Compliance Plan

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

Appendix CAM, Compliance Assurance Monitoring Plan

Appendix SO-1, Secretarial ORDER(s)

Appendix SS-1, Stack Sampling Facilities (version dated 10/7/96)

Appendix TV-4, Title V Conditions (version dated 2/12/02)

ASP Number 97-B-01
(With Scrivener's Order Dated July 9, 1997)

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

Table 2-1, Compliance Requirements

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)]

<u>40 CFR 64.10 Savings Provisions.</u>

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]

Emissions Unit -004

1,096.7 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 1. MONITORING APPROACH FOR UNIT -004

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in the ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 27%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. An exceedance of the PM limit occurs if the opacity is greater than 30% for 3 hours.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	E. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data.
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -005

1,096.7 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 2. MONITORING APPROACH FOR UNIT -005

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in the ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 28%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. An exceedance of the PM limit occurs if the opacity is greater than 31% for 3 hours.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	F. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data.
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -006

3,704.8 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 3. MONITORING APPROACH FOR UNIT -006

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 33%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. An exceedance of the PM limit occurs if the opacity is greater than 37% for 3 hours.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	G. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data.
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -007

6,406.4 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 4. MONITORING APPROACH FOR UNIT -007

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 6-minute opacity average greater than 18%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. An exceedance of the Opacity limit occurs if the opacity is greater than 20% for any 6-minute average. An exceedance of the opacity limit will most likely occur before the PM limit is reached.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	H. Data Collection Procedures	The DAS retains all 6-minute average opacity data.
	F. Averaging Period	6-minute averages.

PLANT CRIST
Unit 4
Compliance Assurance Monitoring Plan
Electrostatic Precipitators for Particulate Matter Control

A. Compliance Approach: Test and Cap

The "Test and Cap" approach is applicable for units with an acceptable compliance margin. Under this approach an opacity cap, as ~~determined by~~ testing, is set at the opacity level which correlates to the ~~permitted~~ particulate limit. This opacity value is also the CAM ~~excursion~~ level. If the curve still does not reach the particulate emission limit, then the cap is set at the maximum opacity on the curve as long as this value does not exceed the six minute opacity limit for the source. A CAM corrective action trigger level is set at 90% of the opacity cap. If the three-hour opacity average approaches the CAM corrective action trigger level, corrective action will be taken to avoid going above the CAM excursion level. A three-hour opacity value greater than the opacity cap would be reported on the semi-annual compliance report as a CAM ~~excursion~~. exceedance

exceedance

expansion

In the presumptively acceptable CAM protocol for precipitators, EPA allows extrapolation of the curve by up to 25% of the highest particulate emissions level tested. While these protocols are not the same, the testing required is identical. In order to avoid exceeding particulate emission limits during CAM testing, Gulf Power will also use this approach. ?

B. Background

a. Emission Unit:

Description:	Coal-fired boiler
Identification:	Unit 4
Pollution Control Device:	Hot-Side ESP 4, Cold-Side ESP 4
Facility:	Plant Crist 11999 Pate Street Pensacola, FL 32514

b. Applicable Regulation, Emissions Limit, and Monitoring Requirements:

Regulation:	Title V Permit, State regulation
Emissions Limits	
PM:	0.1 lbs/mmbtu
Opacity:	40% (6-minute average)
CAM Opacity Cap:	30% (3-hour block average)
CAM Corrective Action Trigger Level:	27% (3-hour block average)
Monitoring Requirements:	Continuous opacity monitoring system

c. Control Technology: Electrostatic precipitator

C. Monitoring Approach

The key elements of the monitoring approach, including the indicators to be monitored, indicator ranges, and performance criteria are presented in Table 1. The CAM performance indicator is the opacity of the exhaust from the Unit 4 cold-side electrostatic precipitator (ESP) measured in the outlet duct. The CAM corrective action opacity trigger and excursion levels were established based on ESP performance test data collected at varying operating conditions.

The operating conditions tested were normal baseline and two sets of "detuned" conditions. The detuned conditions were established by turning off or limiting Transformer-Rectifier sections in the hot-side and cold-side ESP's. The ESP's were detuned to simulate conditions that might occur during ESP malfunctions. The ESP particulate matter emissions at each condition were measured using EPA Method 17. The detailed emissions test reports for each condition are attached.

D. Justification

a. Background

The pollutant-specific emission units are a hot-side and cold-side ESP's controlling particulate emissions from a Combustion Engineering tangentially-fired boiler with a rated steam flow capacity of 582,000 lbs/hr. The unit's rated generation capacity is 75 MW. The ESP exhaust through an outlet duct before entering the stack. Compliance monitoring and testing is performed in the outlet duct as required by the Title V Permit.

The Unit 4 boiler was placed into service in 1959 and burns Eastern bituminous coal. The hot-side ESP is 27 feet long by 36 feet high with a nominal gross specific collection area of 280 ft^2/1000 ACFM. The cold-side ESP is 18 feet long by 30 feet high with a nominal gross specific collection area of 145 ft^2/1000 ACFM.

b. Rationale for Selection of Performance Indicators

The selected CAM indicator is the opacity of the Unit 4 cold-side ESP exhaust. Opacity was selected as the performance indicator because as opacity increases it can be reasonably assumed that PM emissions also increase. Although ~~the correlation between~~ opacity and PM emissions is not exact over all operating conditions, the margin of compliance shown during ESP testing at high opacity levels indicates reasonable assurance that PM emissions should be below the permit limit at a wide range of operating conditions.

? not so

c. Rationale for Selection of Opacity Indicator Levels

The corrective action opacity trigger level selected was a three-hour average greater than or equal to 27%. When the opacity is ~~below this~~ level, test data indicates a reasonable assurance that the PM emissions will be less than the permit limit. If the three-hour opacity average increases to 27% or above, action will be taken to bring the average below 27% as

too long
1hr?
30 min ?

soon as possible. If the 3 hour opacity average exceeds 30%, a CAM excursion has occurred.

The CAM corrective action opacity trigger and excursion levels were established by measuring the particulate emissions at different opacity levels in the ESP exhaust. The measured particulate emissions were plotted against the observed opacity and the best fit curve was applied. The highest average opacity tested was 29.1%. At this opacity the PM rate was 0.097 lbs/mmbtu. The projected particulate emission rate at 30% opacity using the equation generated by the best fit curve is 0.10 lbs/mmbtu. As can be seen, this is equal to the permit limit of 0.1 lbs/mmbtu, so the CAM opacity excursion level is set at 30%. The CAM corrective action opacity trigger level is set at 90% of the excursion level to provide a reasonable margin to correct ESP problems before an excursion occurs. The test results are summarized in Table 2 and Figure 1.

Violation

The stated intent of the CAM rule is to ensure that control devices are properly operated and maintained. Proper operation of the particulate control device, the electrostatic precipitator, cannot be assessed during unit start-up and shutdown (both controlled and uncontrolled, *e.g.*, during equipment malfunction). During these times, low temperatures and varying fuels cause the precipitators to be naturally unstable. In addition, the CAM testing preformed to develop the opacity cap and corrective action trigger levels was done only under maximum stable loads, with out start-up fuel. CAM monitoring is therefore not required while units are in start-up or shutdown mode.

d. <u>Corrective Actions</u>
Actions taken to correct deficient ESP performance may include the following:
   i. Verify all transformer-rectifiers are in service and working properly.
   ii. Verify flue gas conditioning system is functioning correctly.
   iii. Verify discharge and collecting rappers are working properly.
   iv. Verify ash removal equipment is running properly.

If corrective action fails to lower the opacity, the unit load will be reduced until the opacity is below the CAM excursion level.

e. <u>Rationale for Selection of CAM Averaging Periods</u>
Since the particulate standard is based on a three hour average, an averaging period of three hours was chosen for determination of a CAM excursion. In addition, the CAM corrective action trigger level is set such that action is taken prior to exceeding the CAM opacity cap.

TABLE 1. MONITORING APPROACH

I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in the ESP outlet duct.
II.	Indicator Range	The corrective action opacity trigger level is a 3-hour opacity greater than or equal to 27%. If the 3-hour opacity is outside the corrective action trigger level, action will immediately be taken to lower the opacity. An excursion occurs if the 3-hour opacity is greater than 30%. exceedance
III.	Performance Criteria A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices/Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data..
	Averaging period	The 6-minute opacity data is used to calculate 3-hour block averages.

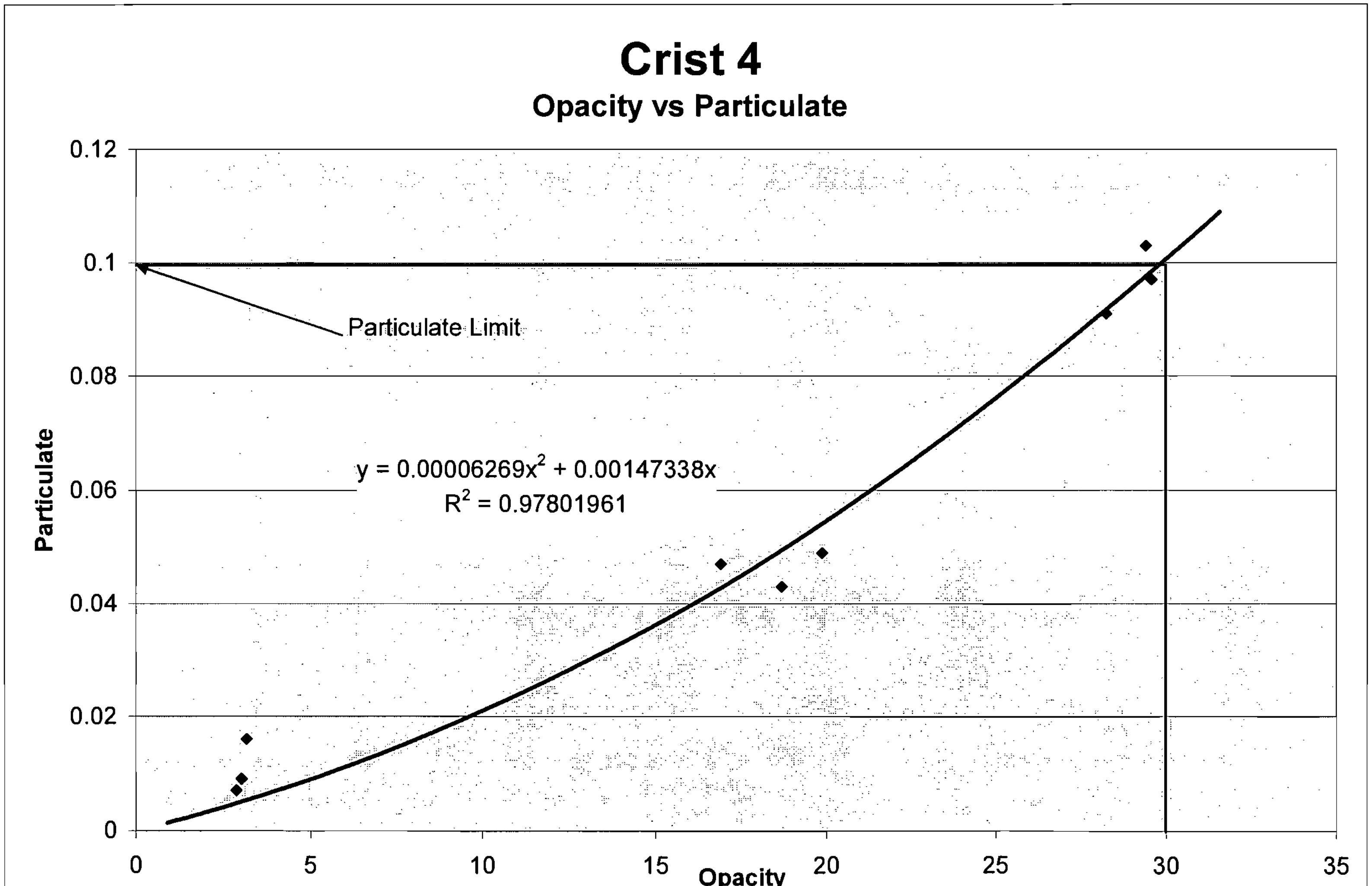
CAM Protocol for an ESP Controlling PM from a Coal-Fired Boiler

Crist 4
CAM Test Data Summary

	Baseline		Condition 1		Condition 2	
	Opacity	Particulate	Opacity	Particulate	Opacity	Particulate
Run 1	3.2	0.016	16.9	0.047	29.4	0.103
Run 2	3.1	0.009	18.7	0.043	29.6	0.097
Run 3	2.9	0.007	19.9	0.049	28.3	0.091
Average	**3.1**	**0.011**	**18.5**	**0.046**	**29.1**	**0.097**

Table 2

- Best fit equation for opacity versus particulate is **$y=0.00006269x^2 + 0.00147338x$** y=particulate emissions, x=opacity
- **$R^2=0.9780$**, R^2 is the Coefficient of Determination. It is the percent of variance of one variable explained by the other. The value of 0.9780 shows that 97.80% of the variability in particulate matter is explained by opacity.
- Projected particulate at 30% opacity = **$0.00006269(30)^2 + 0.00147338(30) = 0.10$**
- Projected particulate is equal to the permit limit of 0.1, so the CAM excursion level is set at 30% opacity. The CAM corrective action trigger level is set at 27% opacity (0.9*30%).


Crist 4
Opacity vs Particulate
Particulate
0.12
0.1
0.08
0.06
0.04
0.02
0
Particulate Limit
y = 0.00006269x2 + 0.00147338x
R2 = 0.97801961
0
5
10
15
20
25
30
35
Opacity
Figure 1

PLANT CRIST
Unit 5
Compliance Assurance Monitoring Plan
Electrostatic Precipitators for Particulate Matter Control

A. Compliance Approach: Test and Cap

The "Test and Cap" approach is applicable for units with an acceptable compliance margin. Under this approach an opacity cap, as determined by testing, is set at the opacity level which correlates to the permitted particulate limit. This opacity value is also the CAM excursion level. If the curve still does not reach the particulate emission limit, then the cap is set at the maximum opacity on the curve as long as this value does not exceed the six minute opacity limit for the source. A CAM corrective action trigger level is set at 90% of the opacity cap. If the three-hour opacity average approaches the CAM corrective action trigger level, corrective action will be taken to avoid going above the CAM excursion level. A three-hour opacity value greater than the opacity cap would be reported on the semi-annual compliance report as a CAM excursion.

In the presumptively acceptable CAM protocol for precipitators, EPA allows extrapolation of the curve by up to 25% of the highest particulate emissions level tested. While these protocols are not the same, the testing required is identical. In order to avoid exceeding particulate emission limits during CAM testing, Gulf Power will also use this approach.

B. Background

a. Emission Unit:

Description:	Coal-fired boiler
Identification:	Unit 5
Pollution Control Device:	Hot-Side ESP 5, Cold-Side ESP 5
Facility:	Plant Crist 11999 Pate Street Pensacola, FL 32514

b. Applicable Regulation, Emissions Limit, and Monitoring Requirements:

Regulation:	Title V Permit, State regulation
Emissions Limits	
PM:	0.1 lbs/mmbtu
Opacity:	40% (6-minute average)
CAM Opacity Cap:	31% (3-hour block average)
CAM Corrective Action Trigger Level:	28% (3-hour block average)
Monitoring Requirements:	Continuous opacity monitoring system

c. Control Technology: Electrostatic precipitator

C. Monitoring Approach

The key elements of the monitoring approach, including the indicators to be monitored, indicator ranges, and performance criteria are presented in Table 1. The CAM performance indicator is the opacity of the exhaust from the Unit 5 cold-side electrostatic precipitator (ESP) measured in the outlet duct. The CAM corrective action opacity trigger and excursion levels were established based on ESP performance test data collected at varying operating conditions.

The operating conditions tested were normal baseline and a "detuned" condition. The detuned condition was established by turning off or limiting Transformer-Rectifier sections in the hot-side and cold-side ESP's. The ESP's were detuned to simulate conditions that might occur during ESP malfunctions. The ESP particulate matter emissions at each condition were measured using EPA Method 17. The detailed emissions test reports for each condition are attached.

D. Justification

a. Background

The pollutant-specific emission units are a hot-side and cold-side ESP's controlling particulate emissions from a Combustion Engineering tangentially-fired boiler with a rated steam flow capacity of 582,000 lbs/hr. The unit's rated generation capacity is 75 MW. The ESP exhaust through an outlet duct before entering the stack. Compliance monitoring and testing is performed in the outlet duct as required by the Title V Permit.

The Unit 5 boiler was placed into service in 1961 and burns Eastern bituminous coal. The hot-side ESP is 27 feet long by 36 feet high with a nominal gross specific collection area of 280 ft^2/1000 ACFM. The cold-side ESP is 18 feet long by 30 feet high with a nominal gross specific collection area of 145 ft^2/1000 ACFM.

b. Rationale for Selection of Performance Indicators

The selected CAM indicator is the opacity of the Unit 5 cold-side ESP exhaust. Opacity was selected as the performance indicator because as opacity increases, it can be reasonably assumed that PM emissions also increase. Although the correlation between opacity and PM emissions is not exact over all operating conditions, the margin of compliance shown during ESP testing at high opacity levels indicates reasonable assurance that PM emissions should be below the permit limit at a wide range of operating conditions.

c. Rationale for Selection of Opacity Indicator Levels

The corrective action opacity trigger level selected was a three-hour average greater than or equal to 28%. When the opacity is below this level, test data indicates a reasonable assurance that the PM emissions will be less than the permit limit. If the three-hour opacity average increases to 28% or above, action will be taken to bring the average below 28% as soon as possible. If the 3 hour opacity average exceeds 31%, a CAM excursion has occurred.

The CAM corrective action opacity trigger and excursion levels were established by measuring the particulate emissions at different opacity levels in the ESP exhaust. The measured particulate emissions were plotted against the observed opacity and the best fit curve was applied. The highest average opacity tested was 28.9%. At this opacity the PM rate was 0.085 lbs/mmbtu. The projected particulate emission rate at 31% opacity using the equation generated by the best fit curve is 0.10 lbs/mmbtu. As can be seen, this is equal to the permit limit of 0.1 lbs/mmbtu, so the CAM opacity excursion level is set at 31%. The CAM corrective action opacity trigger level is set at 90% of the excursion level to provide a reasonable margin to correct ESP problems before an excursion occurs. The test results are summarized in Table 2 and Figure 1.

The stated intent of the CAM rule is to ensure that control devices are properly operated and maintained. Proper operation of the particulate control device, the electrostatic precipitator, cannot be assessed during unit start-up and shutdown (both controlled and uncontrolled, *e.g.*, during equipment malfunction). During these times, low temperatures and varying fuels cause the precipitators to be naturally unstable. In addition, the CAM testing preformed to develop the opacity cap and corrective action trigger levels was done only under maximum stable loads, with out start-up fuel. CAM monitoring is therefore not required while units are in start-up or shutdown mode.

d. Corrective Actions
Actions taken to correct deficient ESP performance may include the following:
   i. Verify all transformer-rectifiers are in service and working properly.
   ii. Verify flue gas conditioning system is functioning correctly.
   iii. Verify discharge and collecting rappers are working properly.
   iv. Verify ash removal equipment is running properly.

If corrective action fails to lower the opacity, the unit load will be reduced until the opacity is below the CAM excursion level.

e. Rationale for Selection of CAM Averaging Periods
Since the particulate standard is based on a three hour average, an averaging period of three hours was chosen for determination of a CAM excursion. In addition, the CAM corrective action trigger level is set such that action is taken prior to exceeding the CAM opacity cap.

TABLE 1. MONITORING APPROACH

I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in the ESP outlet duct.
II.	Indicator Range	The corrective action opacity trigger level is a 3-hour opacity greater than or equal to 28%. If the 3-hour opacity is outside the corrective action trigger level, action will immediately be taken to lower the opacity. An excursion occurs if the 3-hour opacity is greater than 31%.
III.	Performance Criteria A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices/Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data..
	Averaging period	The 6-minute opacity data is used to calculate 3-hour block averages.

CAM Protocol for an ESP Controlling PM from a Coal-Fired Boiler

Crist 5
CAM Test Data Summary

	Baseline		Condition 1	
	Opacity	Particulate	Opacity	Particulate
Run 1	10.2	0.014	27.6	0.077
Run 2	10.2	0.013	28.9	0.089
Run 3	10.0	0.013	30.0	0.088
Average	**10.1**	**0.013**	**28.9**	**0.085**

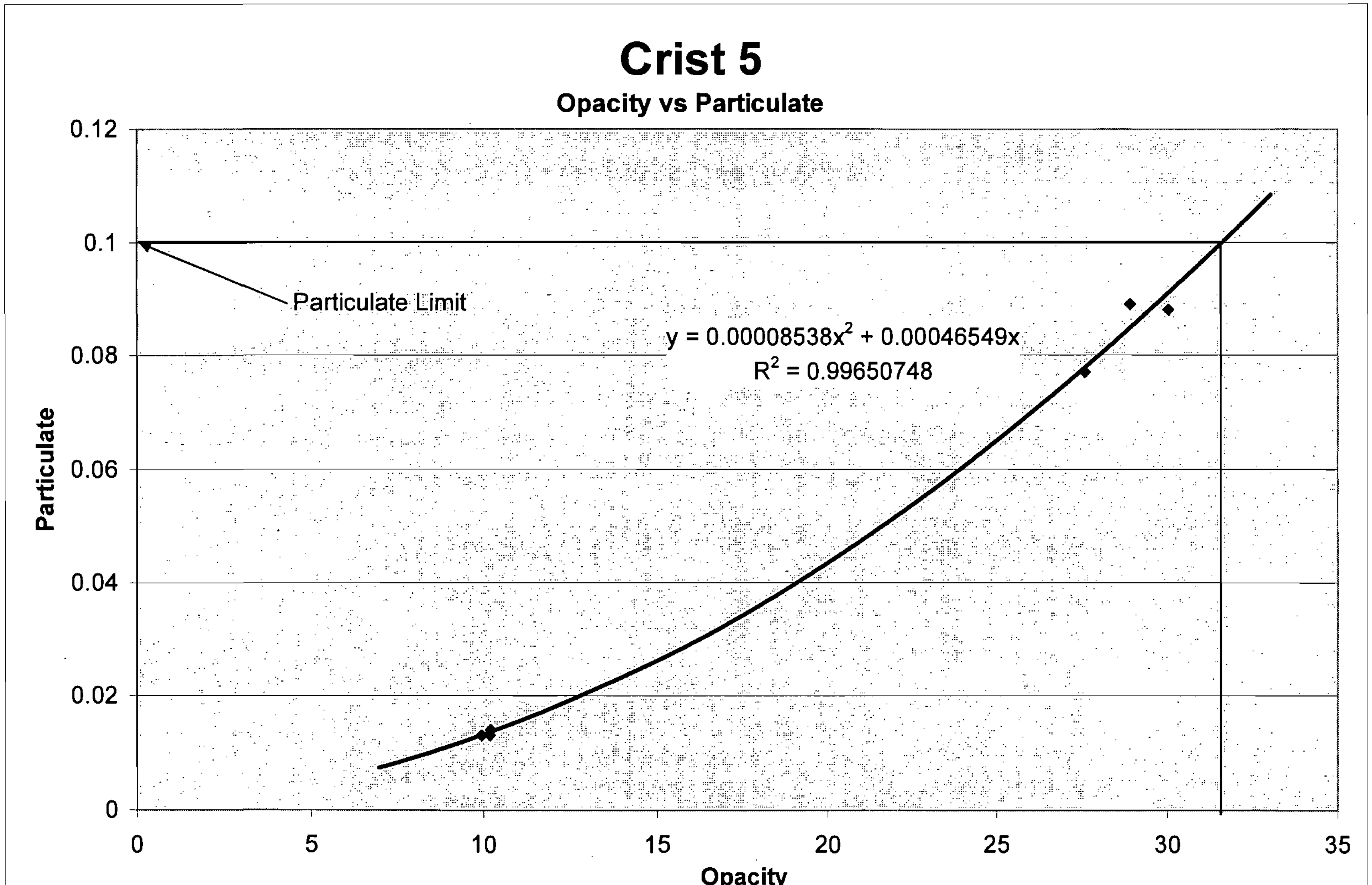
Table 2

- Best fit equation for opacity versus particulate is **$y=0.00008538x^2 + 0.00046549x$**
  y=particulate emissions, x=opacity

- **R^2=0.9965**, R^2 is the Coefficient of Determination. It is the percent of variance of one variable explained by the other. The value of 0.9965 shows that 99.65% of the variability in particulate matter is explained by opacity.

- Projected particulate at 30% opacity = **$0.00008538(31)^2 + 0.00046549(31) = 0.10$**

- Projected particulate is equal to the permit limit of 0.1, so the CAM excursion level is set at 31% opacity. The CAM corrective action trigger level is set at 28% opacity (0.9*31%).


Crist 5
Opacity vs Particulate
Particulate Limit
y = 0.00008538x2 + 0.00046549x
R2 = 0.99650748
Particulate
Opacity
0
0.02
0.04
0.06
0.08
0.1
0.12
0
5
10
15
20
25
30
35
Figure 1

PLANT CRIST
Unit 6
Compliance Assurance Monitoring Plan
Electrostatic Precipitators for Particulate Matter Control

A. Compliance Approach: Test and Cap

The "Test and Cap" approach is applicable for units with an acceptable compliance margin. Under this approach an opacity cap, as determined by testing, is set at the opacity level which correlates to the permitted particulate limit. This opacity value is also the CAM excursion level. If the curve still does not reach the particulate emission limit, then the cap is set at the maximum opacity on the curve as long as this value does not exceed the six minute opacity limit for the source. A CAM corrective action trigger level is set at 90% of the opacity cap. If the three-hour opacity average approaches the CAM corrective action trigger level, corrective action will be taken to avoid going above the CAM excursion level. A three-hour opacity value greater than the opacity cap would be reported on the semi-annual compliance report as a CAM excursion.

In the presumptively acceptable CAM protocol for precipitators, EPA allows extrapolation of the curve by up to 25% of the highest particulate emissions level tested. While these protocols are not the same, the testing required is identical. In order to avoid exceeding particulate emission limits during CAM testing, Gulf Power will also use this approach.

B. Background

a. Emission Unit:

Description:	Coal-fired boiler
Identification:	Unit 6
Pollution Control Device:	ESP 6
Facility:	Plant Crist 11999 Pate Street Pensacola, FL 32514

b. Applicable Regulation, Emissions Limit, and Monitoring Requirements:

Regulation:	Title V Permit, State regulation
Emissions Limits	
PM:	0.1 lbs/mmbtu
Opacity:	40% (6-minute average)
CAM Opacity Cap:	37% (3-hour block average)
CAM Corrective Action Trigger Level:	33% (3-hour block average)
Monitoring Requirements:	Continuous opacity monitoring system

c. Control Technology: Electrostatic precipitator

C. Monitoring Approach

The key elements of the monitoring approach, including the indicators to be monitored, indicator ranges, and performance criteria are presented in Table 1. The CAM performance indicator is the opacity of the exhaust from the Unit 6 cold-side electrostatic precipitator (ESP) measured in the outlet duct. The CAM corrective action opacity trigger and excursion levels were established based on ESP performance test data collected at varying operating conditions.

The operating conditions tested were normal baseline and two sets of "detuned" conditions. The detuned conditions were established by turning off or limiting Transformer-Rectifier sections in the ESP. The ESP was detuned to simulate conditions that might occur during ESP malfunctions. The ESP particulate matter emissions at each condition were measured using EPA Method 17. The detailed emissions test reports for each condition are attached.

D. Justification

a. Background

The pollutant-specific emissions unit is a cold-side ESP controlling particulate emissions from a Foster Wheeler wall-fired boiler with a rated steam flow capacity of 2,337,300 lbs/hr. The unit's rated generation capacity is 320 MW. The ESP exhaust through an outlet duct before entering the stack. Compliance monitoring and testing is performed in the outlet duct as required by the Title V Permit.

The Unit 6 boiler was placed into service in 1970 and burns Eastern bituminous coal. The ESP is 58.8 feet long by 49 feet high with a nominal gross specific collection area of 393 ft^2/1000 ACFM.

b. Rationale for Selection of Performance Indicators

The selected CAM indicator is the opacity of the Unit 6 cold-side ESP exhaust. Opacity was selected as the performance indicator because as opacity increases, it can be reasonably assumed that PM emissions also increase. Although the correlation between opacity and PM emissions is not exact over all operating conditions, the margin of compliance shown during ESP testing at high opacity levels indicates reasonable assurance that PM emissions should be below the permit limit at a wide range of operating conditions.

c. Rationale for Selection of Opacity Indicator Levels

The corrective action opacity trigger level selected was a three-hour average greater than or equal to 33%. When the opacity is below this level, test data indicates a reasonable assurance that the PM emissions will be less than the permit limit. If the three-hour opacity average increases to 33% or above, action will be taken to bring the average below 33% as soon as possible. If the 3 hour opacity average exceeds 37%, a CAM excursion has occurred.

The CAM corrective action opacity trigger and excursion levels were established by measuring the particulate emissions at different opacity levels in the ESP exhaust. The measured particulate emissions were plotted against the observed opacity and the best fit curve was applied. The highest average opacity tested was 32.8%. At this opacity the PM emission rate was 0.060 lbs/mmbtu. The projected particulate emission rate at 37% opacity using the equation generated by the best fit curve is 0.075 lbs/mmbtu. The projected particulate is extrapolated by approximately 25% above the highest measured particulate as allowed by the ESP CAM protocol. As can be seen, this is below the permit limit of 0.1 lbs/mmbtu, so the CAM opacity excursion level is set at 37%. The CAM corrective action opacity trigger level is set at 90% of the excursion level to provide a reasonable margin to correct ESP problems before an excursion occurs. The test results are summarized in Table 2 and Figure 1.

The stated intent of the CAM rule is to ensure that control devices are properly operated and maintained. Proper operation of the particulate control device, the electrostatic precipitator, cannot be assessed during unit start-up and shutdown (both controlled and uncontrolled, *e.g.*, during equipment malfunction). During these times, low temperatures and varying fuels cause the precipitators to be naturally unstable. In addition, the CAM testing preformed to develop the opacity cap and corrective action trigger levels was done only under maximum stable loads, with out start-up fuel. CAM monitoring is therefore not required while units are in start-up or shutdown mode.

d. <u>Corrective Actions</u>
Actions taken to correct deficient ESP performance may include the following:
   i. Verify all transformer-rectifiers are in service and working properly.
   ii. Verify flue gas conditioning system is functioning correctly.
   iii. Verify discharge and collecting rappers are working properly.
   iv. Verify ash removal equipment is running properly.

If corrective action fails to lower the opacity, the unit load will be reduced until the opacity is below the CAM excursion level.

e. <u>Rationale for Selection of CAM Averaging Periods</u>
Since the particulate standard is based on a three hour average, an averaging period of three hours was chosen for determination of a CAM excursion. In addition, the CAM corrective action trigger level is set such that action is taken prior to exceeding the CAM opacity cap.

TABLE 1. MONITORING APPROACH

I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in ESP outlet duct.
II.	Indicator Range	The corrective action opacity trigger level is a 3-hour opacity greater than or equal to 33%. If the 3-hour opacity is outside the corrective action trigger level, action will immediately be taken to lower the opacity. An excursion occurs if the 3-hour opacity is greater than 37%.
III.	Performance Criteria A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices/Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data..
	Averaging period	The 6-minute opacity data is used to calculate 3-hour block averages.

CAM Protocol for an ESP Controlling PM from a Coal-Fired Boiler

Crist 6
CAM Test Data Summary

	Baseline		Condition 1		Condition 2	
	Opacity	Particulate	Opacity	Particulate	Opacity	Particulate
Run 1	7.3	0.004	25.1	0.040	32.1	0.055
Run 2	7.2	0.005	27.6	0.038	33.1	0.061
Run 3	7.2	0.004	27.2	0.038	33.2	0.064
Average	**7.2**	**0.004**	**26.6**	**0.039**	**32.8**	**0.060**

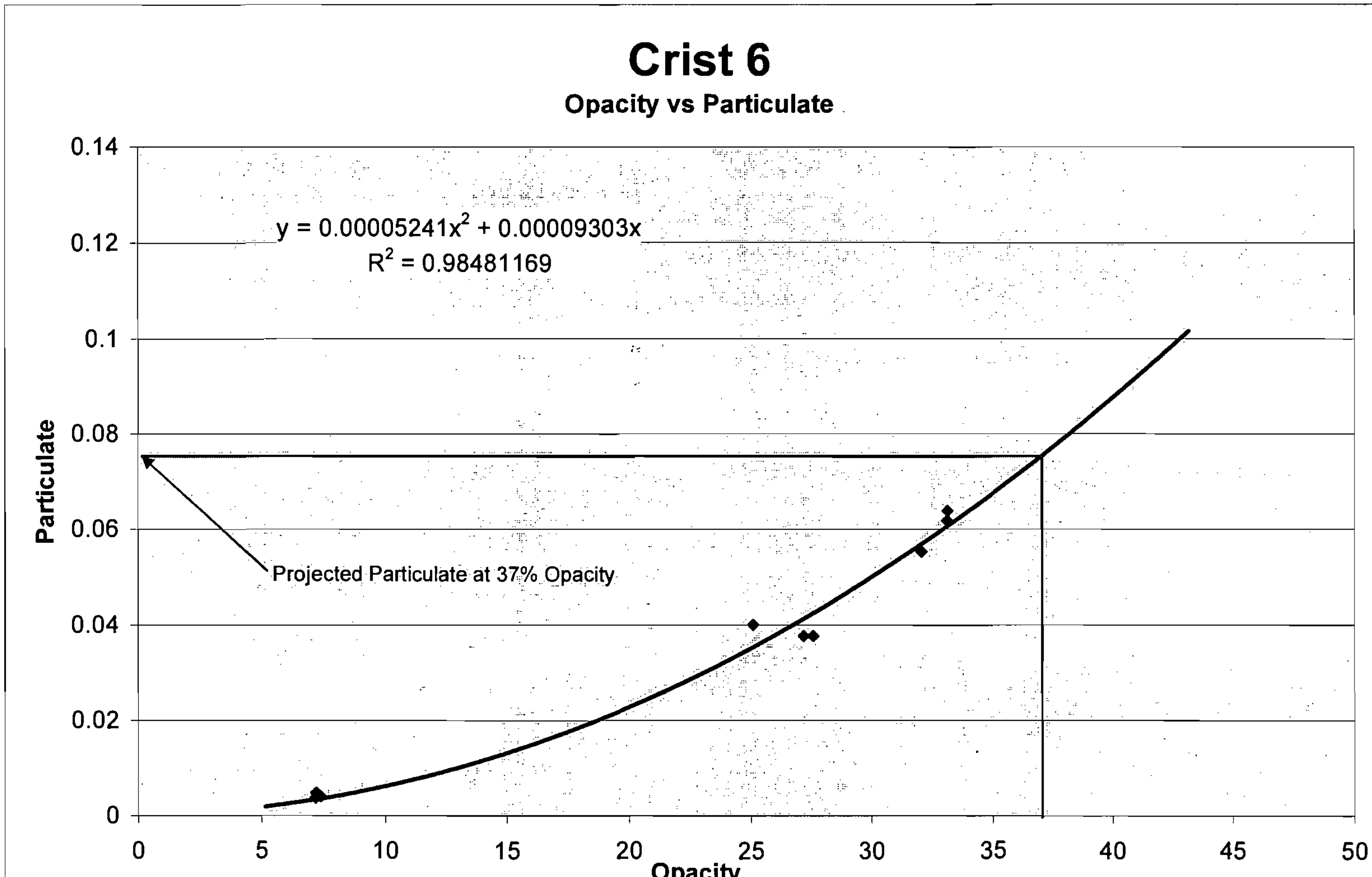
Table 2

- Best fit equation for opacity versus particulate is **$y=0.00005241x^2 + 0.00009303x$**
  y=particulate emissions, x=opacity

- **$R^2=0.9848$**, R^2 is the Coefficient of Determination. It is the percent of variance of one variable explained by the other. The value of 0.9848 shows that 98.48% of the variability in particulate matter is explained by opacity.

- Projected particulate at 37% opacity = **$0.00005241(37)^2 + 0.00009303(37)$** = **0.075.** This value is 25% greater than the highest measured value of 0.060.

- Projected particulate is less than the permit limit of 0.1, so the CAM excursion level is set at 37% opacity. The CAM corrective action trigger level is set at 33% opacity (0.9*37%).



Crist 6
Opacity vs Particulate
y = 0.00005241x2 + 0.00009303x
R2 = 0.98481169
Projected Particulate at 37% Opacity
Particulate
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0
5
10
15
20
25
30
35
40
45
50
Opacity

Figure 1

PLANT CRIST
Unit 7
Compliance Assurance Monitoring Plan
Electrostatic Precipitators for Particulate Matter Control

A. Compliance Approach: Cap
The "Cap" approach is applicable for units with an acceptable compliance margin. Under this approach an opacity cap, as determined by past testing, is set at the opacity level which correlates to the permitted particulate limit. This opacity value is also the CAM excursion level. If the three-hour opacity average approaches the CAM corrective action trigger level, corrective action will be taken to avoid going above the CAM excursion level. A three-hour opacity value greater than the opacity cap would be reported on the semi-annual compliance report as a CAM excursion.

Gulf Power Company is in the process of constructing a new precipitator for utilization on unit 7. The anticipated completion date will be the first part of May 2004. At this point Gulf Power Company proposes a temporary opacity trigger which should keep particulate levels to be below 0.1 lb/mmBtu.

In order to monitor a surrogate for opacity at a conservative level, Gulf Power Company proposes a temporary cap of 20% for a three hour block average.

B. Background
a. Emission Unit:

Description:	Coal-fired boiler
Identification:	Unit 7
Pollution Control Device:	ESP 7
Facility:	Plant Crist 11999 Pate Street Pensacola, FL 32514

b. Applicable Regulation, Emissions Limit, and Monitoring Requirements:

Regulation:	Title V Permit, State regulation
Emissions Limits	20%
PM:	0.1 lbs/mmbtu
Opacity:	~~40% (6~~-minute average)
CAM Opacity Cap:	To be determined once new precipitator Installed (3-hour block average).
CAM Corrective Action Trigger Level:	20% (3-hour block average)
Monitoring Requirements:	Continuous opacity monitoring system

c. Control Technology: Electrostatic precipitator

C. Monitoring Approach

Once the new precipitator is installed in 2004, CAM testing of the unit will be conducted. We will then we utilize the monitoring approach, including the indicators to be monitored, indicator ranges, and performance criteria are presented in Table 1. The CAM performance indicator is the opacity of the exhaust from the Unit 7 cold-side electrostatic precipitator (ESP) measured in the outlet duct. The CAM corrective action opacity trigger and excursion levels will be established based on ESP performance test data collected at varying operating conditions.

The operating conditions to be tested will consist of normal baseline and two sets of "detuned" conditions. The detuned conditions will be established by turning off or limiting Transformer-Rectifier sections in the ESP. The ESP will be detuned to simulate conditions that might occur during ESP malfunctions. The ESP particulate matter emissions at each condition were measured using EPA Method 17. The detailed emissions test report for each condition will be provided upon completion of testing.

D. Justification

a. Background

The pollutant-specific emissions unit is a cold-side ESP controlling particulate emissions from a Foster Wheeler wall-fired boiler with a rated steam flow capacity of 3,626,000 lbs/hr. The unit's rated generation capacity is 500 MW. The ESP exhaust through an outlet duct before entering the stack. Compliance monitoring and testing is performed in the outlet duct as required by the Title V Permit.

The Unit 7 boiler was placed into service in 1973 and burns Eastern bituminous coal. The current ESP has a collection area of 202 ft^2/1000 ACFM. The new ESP will have a collection area of 383 ft^2/1000 ACFM.

A comparison of the two precipitators is as follows:

Equipment	Old ESP	New ESP
Emitting Electrode	Weighted	Rigid
SCA (ft^2/KCFM)	202	383
Rappers	324	46
T/R Sets KVA	90	120
Aspect Ratio	0.75	1.22

The new precipitator is predicted to have a collection efficiency of 99.64%.

b. Rationale for Selection of Performance Indicators
The selected CAM indicator is the opacity of the Unit 7 cold-side ESP exhaust. Opacity was selected as the performance indicator because as opacity increases, it can be reasonably assumed that PM emissions also increase. Although the correlation between opacity and PM emissions is not exact over all operating conditions, the margin of compliance shown during ESP testing at high opacity levels for other units indicates reasonable assurance that PM emissions should be below the permit limit at a wide range of operating conditions.

c. Rationale for Selection of Opacity Indicator Levels
The corrective action opacity trigger level selected was a three-hour average greater than or equal to 20%. When the opacity is below this level, test data indicates a reasonable assurance that the PM emissions will be less than the permit limit. If the three-hour opacity average increases to 20% or above, action will be taken to bring the average below 20% as soon as possible. If the 3 hour opacity average exceeds 20%, a CAM excursion has occurred. As stated previously, CAM testing on the new ESP will be conducted once the installation process has been completed.

opacity limit is 20%/6min

The CAM corrective action opacity trigger and excursion levels were established by measuring the particulate emissions at different opacity levels in the ESP exhaust. The measured particulate emissions were plotted against the observed opacity and the best fit curve was applied for years 2001 through 2003. The highest average opacity tested was 13.66%. At this opacity the PM emission rate was 0.049 lbs/mmbtu. The projected particulate emission rate at 20% is approximately 0.095 lbs/mmbtu. As can be seen, this is below the permit limit of 0.1 lbs/mmbtu, so the CAM opacity excursion level is set at 20%. The CAM corrective action opacity trigger level is set at 95% of the excursion level to provide a reasonable margin to correct ESP problems before an excursion occurs. The test results are summarized in Table 1 and Figure 1.

The stated intent of the CAM rule is to ensure that control devices are properly operated and maintained. Proper operation of the particulate control device, the electrostatic precipitator, cannot be assessed during unit start-up and shutdown (both controlled and uncontrolled, *e.g.*, during equipment malfunction). During these times, low temperatures and varying fuels cause the precipitators to be naturally unstable.

The CAM testing to be preformed, once the new ESP is installed, will be used to develop the opacity cap and corrective action trigger levels. The testing will be done only under maximum stable loads, with out start-up fuel. CAM monitoring is therefore not required while units are in start-up or shutdown mode.

d. Corrective Actions

Actions taken to correct deficient ESP performance may include the following:

i. Verify all transformer-rectifiers are in service and working properly.
ii. Verify flue gas conditioning system is functioning correctly.
iii. Verify discharge and collecting rappers are working properly.
iv. Verify ash removal equipment is running properly.

e. Rationale for Selection of CAM Averaging Periods

Since the particulate standard is based on a three hour average, an averaging period of three hours was chosen for determination of a CAM excursion. In addition, the CAM corrective action trigger level is set such that action is taken prior to exceeding the CAM opacity cap.

TABLE 1. MONITORING APPROACH

I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in ESP outlet duct.
II.	Indicator Range	The corrective action opacity trigger level is a 3-hour opacity greater than or equal to 20%. If the 3-hour opacity is outside the corrective action trigger level, action will immediately be taken to lower the opacity. An excursion occurs if the 3-hour opacity is greater than 20%.
III.	Performance Criteria A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices/Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data..
	Averaging period	The 6-minute opacity data is used to calculate 3-hour block averages.

CAM Protocol for an ESP Controlling PM from a Coal-Fired Boiler

Not valid for New ESP

Crist 7
CAM Test Data Summary

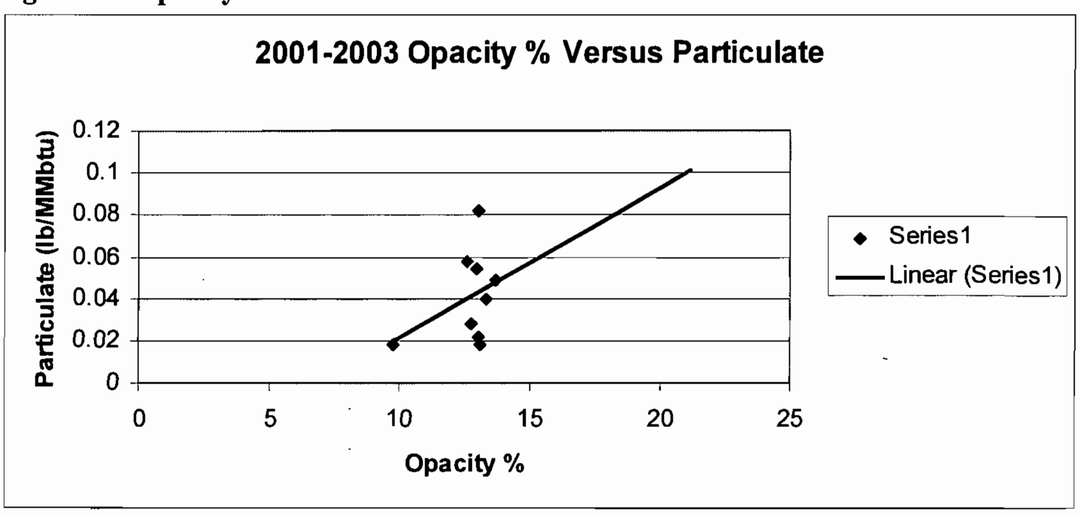
	2001 Steady State		2002 Steady State		2003 Steady State	
	Opacity	Particulate	Opacity	Particulate	Opacity	Particulate
Run 1	13.06	0.082	12.72	0.028	13.12	0.018
Run 2	12.96	0.054	13.30	0.040	13.05	0.022
Run 3	9.76	0.018	12.58	0.058	13.66	0.049
Average	**11.92**	**0.051**	**12.87**	**0.042**	**13.28**	**0.030**

Table 2

2001 Particulate testing conducted on November 13, 2001
2002 Particulate test conducted on June 19, 2002
2003 Particulate test conducted on February 11, 2003

- Projected particulate is less than the permit limit of 0.1, so the temporary CAM excursion level is set at 20% opacity. The CAM corrective action trigger level is set at 20% opacity (0.95*21%).

Figure 1 – Opacity Versus Particulate Matter



An acute shortfall in cement supply has prompted some companies to request moderate production increases at their existing facilities. A few of them are likely to request to build new kilns, said Alvaro Linero, a Permitting Program Administrator at the Florida state Department of Environment. "It's safe to say that additional control equipment would be required for new applications that trigger New Source Review." Most likely that would be selective non-catalytic reduction (SNCR), although we would require the applicant to review SCR using a top-down best achievable control technology assessment (BACT)," he said.

SCR may or may not be technically or economically feasible at a given site, but "it's hard to reject SNCR", he added. "Plants in the United States do not yet use either technology although a few projects are proposed that will incorporate SNCR with limits in the range of 2.4 to 2.8 lb NOx per ton of clinker". The Suwannee American Cement company has a limit of 2.9 lb NOx/ton clinker on a 24-hour basis, and typically achieves approximately 2.3 lb/ton without an SCNR system. BACT for the Florida Rock Industries facility, which started up in 1999 is 2.45 on a 30-day basis without an SNCR system", said Linero.

Sweden has by far the world's lowest limit of 1 lb NOx/ton which is achieved at the Slite Plant in Gottsland with an SNCR system. The plant also has a sulfur dioxide scrubber that helps reduce the excess ammonia emissions and visible detached plumes that can occur when trying to achieve such low values. A plant in Solnhofen Germany has an SCR unit which is capable of achieving similarly low values without the ammonia emissions. "1 lb/ton clinker by SNCR or by SCR would have to be considered in any determination of Lowest Achievable Emission Rate (LAER) for non-attainment areas. It would also be the top technology in a top-down BACT determination".

Box – "1 lb/ton by SNCR or SCR would have to be considered for LAER"

Jim's Review

STATEMENT OF BASIS

Gulf Power Company
Crist Electric Generating Plant
Facility ID No.: 0330045
Escambia County

Title V Air Operation Permit Renewal
DRAFT Permit No.: 0330045-009-AV

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-213. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

This facility consists of six active fossil fuel fired steam generators ~~(boilers)~~ and two fly ash silos. Boilers 4 and 5 are substitution Acid Rain Phase I Units. Boilers 6 and 7 are Acid Rain ~~Phase I~~ Units. All six boilers will be subject to the Acid Rain Phase II requirements. Natural gas is the primary fuel for ~~boilers 1~~, 2 and 3. Pulverized coal is the primary fuel for boilers 4, 5, 6 and 7. Fuel oil is used as supplemental fuel in all seven of the boilers. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Emissions unit number -001 was a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 1". It was permanently removed from service on March 31, 2003. Emissions unit number -002 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 2". It is rated at a maximum heat input of 420 MMBtu/hour when firing natural gas and 320 MMBtu/hour when firing fuel oil. Natural gas is the primary fuel. Emissions unit number -003 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 3". It is rated at a maximum heat input of 550 million Btu per hour (MMBtu/hour) when firing natural gas and/or fuel oil. Natural gas is the primary fuel. Units 2 and 3 are regulated under Acid Rain, Phase II. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. Emissions from these boilers are uncontrolled. Units 2 and 3 are scheduled to be removed from service no later than May 1, 2006. The Department feels that additional periodic monitoring for particulate matter (PM) emissions is not needed for these units. For each of the past ten years, these units have burned fuel oil for less than 400 hours. Under the approval granted by an alternate sampling procedure (ASP 97-B-01) accepted by EPA, as long as these units do not burn liquid or solid fuel for greater than 400 hours per year, annual particulate matter tests are not required.

Emissions unit number -004 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 4". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Emissions unit number -005 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 5". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Both units are Phase I Substitution and Phase II Acid Rain Units. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from units -004 and -005 are controlled by hot side (Buell Model # Bal. 2x34n333-4-3p) and cold side (Buell Model # 1.1x48k33-1p) electrostatic precipitators.

Emissions unit number -006 is a Foster Wheeler front wall fired, dry bottom boiler designated as "Boiler Number 6". It is rated at a maximum heat input of 3,704.8 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate fuel oil (used as back-up fuel). Emissions unit number -007 is a Foster Wheeler front and rear wall fired, dry bottom boiler designated as "Boiler Number 7". It is rated at a maximum heat input of 6,406.4 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate fuel oil (used as back-up fuel). These emissions units are regulated under Acid Rain, Phase I. These emissions units pre-date PSD regulations, but are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from unit -006 are controlled by a cold side electrostatic precipitator (Wheelabrator Model # HaRDE). PM emissions from unit -007 are controlled by cold side Buell electrostatic precipitators. NO_X emissions from units -006 and -007 are controlled by Foster Wheeler Low NO_x Burners. Emissions unit –006 contains a PM limitation of 1,475 tons per year. This limit was established by a construction permit that was issued (in 1993) to install a new electrostatic precipitator. It was calculated based on the allowable emission limit, the maximum demonstrated heat input rate at that time, and the assumption of continuous operation (8,760 hours per year). With the issuance of this permit, a slightly higher (but now federally enforceable) heat input rate has been established. Even though the maximum potential PM emissions are now 1,623 tons per year, compliance with the enforceable 1,475 ton per year limit will be assured based on the low historical particulate matter emissions test results (see table below).

Unit #	Steady-state	Soot-blowing
4	0.011	0.016
5	0.039	0.035
6	0.007	0.010
7	0.041	0.062

Boilers 4, 5, 6 and 7 are utilizing CEMS for compliance purposes for NO_X, SO_2 and opacity.

Boilers 4, 5, 6 and 7 are subject to CAM for controlled emissions of particulate matter.

Emissions unit number 8 consists of two Fly Ash Storage Silos. Fly ash collection systems from precipitators on boilers numbers 4, 5, 6 & 7 to three transfer tanks are totally enclosed with no emission points. Three blowers pneumatically convey dry fly ash to 2 silos at a maximum solids rate of 150 tons per hour to either silo or to both. The majority of the solids (99.4%) settles by gravity upon entering the silo, the residual particulates are controlled by a baghouse on each silo. Each baghouse is a Pulse Jet Fabric Filter - model #100 - WMWC - 420 (IIG) manufactured by Flex-Kleen. Dry fly ash will be transported in closed tanker trucks away from the site (approximately 20% sold annually) or conditioned (12-15% water added) fly ash will be transported to an approved landfill area on the site. This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required and Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards. There is one baghouse on each silo. Historical test data presented by Gulf Power shows less than 2.2% opacity from these units for the past 5 years. Based on these results, the Department does not feel that additional periodic monitoring is necessary.

Based on the Title V permit renewal application received June 22, 2004, this facility is a major source of hazardous air pollutants (HAPs).

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. <u>Response to excursions or exceedances.</u>

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. <u>Documentation of need for improved monitoring.</u> 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)]

<u>40 CFR 64.8 Quality Improvement Plan (QIP) Requirements.</u>

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. <u>Elements of a QIP</u>:

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)]

<u>40 CFR 64.10 Savings Provisions.</u>

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]

Emissions Unit -004

1,096.7 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 1. MONITORING APPROACH FOR UNIT -004

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in the ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 27%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. An exceedance of the PM limit occurs if the opacity is greater than 30% for 3 hours.
III.	Performance Criteria A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	E. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data..
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -005

1,096.7 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 2. MONITORING APPROACH FOR UNIT -005

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in the ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 28%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. An exceedance of the PM limit occurs if the opacity is greater than 31% for 3 hours.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	F. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data..
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -006

**3,704.8 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP**

Monitoring Approach

TABLE 3. MONITORING APPROACH FOR UNIT -006

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 33%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. An exceedance of the PM limit occurs if the opacity is greater than 37% for 3 hours.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	G. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data..
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -007

6,406.4 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 4. MONITORING APPROACH FOR UNIT -007

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 6-minute opacity average greater than 18%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. An exceedance of the Opacity limit occurs if the opacity is greater than 20% for any 6-minute average. An exceedance of the opacity limit will most likely occur before the PM limit is reached.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	H. Data Collection Procedures	The DAS retains all 6-minute average opacity data.
	F. Averaging Period	6-minute averages.

Gulf Power Company
Crist Electric Generating Plant
Facility ID No.: 0330045
Escambia County

Title V Air Operation Permit
DRAFT Permit No.: 0330045-009-AV

Renewal of Initial Title V Air Operation Permit No.: 0330045-001-AV

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

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

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

Title V Air Operation Permit

DRAFT Permit No.: 0330045-009-AV

Table of Contents

Permittee:
Gulf Power Company
500 Bay Front Parkway
Pensacola, Florida 32520-0100

DRAFT Permit No.: 0330045-009-AV
Facility ID No.: 0330045
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Renewal

This permit is for the operation of the Crist Electric Generating Plant. This facility is located on Pate Road, off of 10 Mile Road on Governors Bayou, Escambia County, North of Pensacola.

STATEMENT OF BASIS: This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Phase II Acid Rain Permit Application/Compliance Plan Signed 06/01/04
Phase II Acid Rain NO_X Compliance Plan Signed 06/01/04
Revised Phase II Acid Rain NO_X Averaging Plan Signed 11/18/03
Appendix SO-1, Secretarial ORDER(s)
Appendix SS-1, Stack Sampling Facilities (version dated 10/7/96)
Appendix TV-4, Title V Conditions (version dated 2/12/02)
ASP Number 97-B-01
Scrivener's Order Correcting ASP Number 97-B-01 (dated July 9, 1997)

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

Michael G. Cooke, Director
Division of Air Resources Management

MGC/jkp/jh

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of five fossil fuel fired steam generators (boilers) and two fly ash silos. Boilers 4 and 5 are substitution Acid Rain Phase I Units. Boilers 6 and 7 are Acid Rain Phase I Units. All five boilers are subject to the Acid Rain Phase II requirements. Natural gas is the primary fuel for boilers 2 and 3. Pulverized coal is the primary fuel for boilers 4, 5, 6 and 7. Fuel oil is used as supplemental fuel in all five of the boilers. Boiler 1 was permanently retired on March 31, 2003. Boilers 2 and 3 will be retired on, or before, May 1, 2006. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the Title V permit renewal application received June 22, 2004, this facility is a major source of hazardous air pollutants (HAPs).

The existing facility is a PSD-major source of air pollution in accordance with Rule 62-212.400, F.A.C.

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

Subsection B. Summary of Emissions Unit ID Numbers and Brief Descriptions.

E.U. ID No.	Brief Description
-001	Boiler Number 1 - 420 MMBtu/hour (retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hour **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hour **(to be retired by May 1, 2006)**
-004	Boiler Number 4 - 1,096.7 MMBtu/hour
-005	Boiler Number 5 - 1,096.7 MMBtu/hour
-006	Boiler Number 6 - 3,704.8 MMBtu/hour
-007	Boiler Number 7 - 6,406.4 MMBtu/hour
-008	Fly Ash Silos (2)
-009	Material Handling of Coal and Ash (See Appendix U-1)
-010	Fugitive PM Sources - On-site Vehicles (See Appendix U-1)
-011	General Purpose Internal Combustion Engines (See Appendix U-1)
-012	Cooling Towers (3) (See Appendix U-1)
-013	Fugitive PM Sources - sandblasting operations (See Appendix U-1)

Please reference the Permit Number, the Facility Identification Number, and the appropriate Emissions Unit(s) ID Number(s) on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The following documents are part of this permit:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Phase II Acid Rain Permit Application/Compliance Plan Signed 6/1/04
Phase II Acid Rain NO_X Compliance Plan Signed 6/1/04
Revised Phase II Acid Rain NO_X Averaging Plan Signed 11/18/03
Appendix SO-1, Secretarial ORDER(s)
Appendix SS-1, Stack Sampling Facilities (version dated 10/7/96)
Appendix TV-4, Title V Conditions (version dated 2/12/02)
ASP Number 97-B-01
Scrivener's Order Correcting ASP Number 97-B-01 (dated July 9, 1997)

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

These documents are provided to the permittee for informational purposes only:
Appendix H-1, Permit History / ID Number Transfers
Phase I Acid Rain Permits Issued December 27, 1994
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers (version dated 2/5/97)
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements

These documents are on file with the permitting authority:
Title V Permit Renewal Application Received June 22, 2004
Title V Application Update (Existing Operation Permits) Received December 2, 1996
Title V Application Revision Request Received April 8, 1997
Title V Application Revision Request Received September 4, 1998

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 one copy when requested or otherwise appropriate. If desired, a copy of Appendix TV-4, Title V Conditions can be downloaded from the Division of Air Resources Management's Internet Web site located at the following address:
http://www.dep.state.fl.us/air/permitting/writertools/t5/TV-4.doc.

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. Prevention of Accidental Releases (Section 112I 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]

4. 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.]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. 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: No vapor emission control devices or systems are deemed necessary nor ordered by the Department as of the issuance date of this permit.}
[Rule 62-296.320(1)(a), F.A.C.]

7. 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.]

8. Emissions of Unconfined Particulate Matter. Pursuant to Rules 62-296.320(4)(c)1., 3. & 4., F.A.C., reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the following requirements (see Condition 57. of APPENDIX TV-4, TITLE V CONDITIONS):

a) Ash leaving the facility will be hauled in closed container trucks. Ash being disposed of on plant property will be mixed with water as it is being loaded into the trucks for transport to the landfill.

b) The plant ash haul roads will be watered as necessary.

c) Grassing over each section of the ash landfill as it reaches its capacity.

d) Regular packing of the coal pile to reduce blowing dust and aid in the prevention of coal fires.

e) Application of a dust suppressant to the coal on the conveyor belts as necessary.

[Rule 62-296.320(4)(c)2., F.A.C.; and, Proposed by applicant in Title V permit renewal application received June 22, 2004.]

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. 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)}

11. The Department's Northwest District Office (Pensacola) telephone number for reporting problems, malfunctions or exceedances under this permit is 850/595-8364, day or night, and for emergencies involving a significant threat to human health or the environment is 850/413-9911. The Department's Northwest District Office (Pensacola) telephone number for routine business, including compliance test notifications, is 850/595-8364 during normal working hours.

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

Department of Environmental Protection
Northwest District Office
160 Governmental Center

Pensacola, Florida 32501-5794
Telephone: 850/595-8364
Fax: 850/595-8417

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

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

13. Any reports, data, notifications, certifications, and requests (other than Acid Rain Program Information) required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency, Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155
Fax: 404/562-9163 or 404/562-9164

14. 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.]

Section III. Emissions Units and Conditions.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-001	Boiler Number 1 - 420 MMBtu/hr (Retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hr **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hr **(to be retired by May 1, 2006)**

Emissions unit number -001 was permanently retired on March 31, 2003. Emissions unit number -002 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 2". It is rated at a maximum heat input of 420 million Btu per hour (MMBtu/hour) when firing natural gas and 320 MMBtu/hour when firing fuel oil. Natural gas is the primary fuel. Emissions unit number -003 is a Riley front wall-fired, dry bottom boiler designated as "Boiler Number 3". It is rated at a maximum heat input of 550 million Btu per hour (MMBtu/hour) when firing natural gas and/or fuel oil. Natural gas is the primary fuel. Units -002 and -003 are regulated under Acid Rain, Phase II. Units -002 and -003 will be permanently retired by My 1, 2006.

{Permitting notes: These emissions units pre-date PSD regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. Emissions from these boilers are uncontrolled. Unit -002 began commercial operation on June 1, 1949. Unit -003 began commercial operation on September 1, 1952. The generator nameplate rating for unit -002 is 28 megawatts (MW). The generator nameplate rating for unit -003 is 39 MW. Units -002 and -003 share a common stack with units -004 and -005. Stack height = 450 feet, exit diameter = 18.0 feet, exit temperature = 290 °F, actual volumetric flow rate = 802,500 acfm.}

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
-002	420	Natural Gas
	320	No. 2 Fuel Oil
	320	No. 6 Fuel Oil
	320	On-Specification Used Oil
-003	550	Natural Gas
	550	No. 2 Fuel Oil
	550	No. 6 Fuel Oil
	550	On-Specification Used Oil

Note: When a blend of fuel oils and natural gas are fired, the heat input shall be prorated based on the percent heat input of each fuel.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.; and, 0330045-010-AC.]

A.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **A.25.**
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation - Fuels. The fuels that are allowed to be burned in these boilers, in any combination with respect to the proration of heat contents, are natural gas, No. 2 fuel oil, No. 6 fuel oil and on-specification used oil (see Specific Condition **A.35.**).
[Rule 62-213.410, F.A.C.; and, Applicant's requests in Title V permit renewal application received June 22, 2004.]

A.4. Hours of Operation. These emissions units may operate continuously, i.e. 8760 hours/year. For each emissions unit, the permittee shall maintain a daily operations log available for Department inspection that documents the total hours of annual operation, including an account of the hours operated on each of the allowable fuels.
[Rules 62-213.440 and 62-210.200(PTE), F.A.C.; and, Applicant's requests in Title V permit renewal application received June 22, 2004.]

Emission Limitations and Standards

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

A.5. Visible Emissions. Visible emissions shall not exceed 20 percent opacity except for one two-minute period per hour during which opacity shall not exceed 40 percent. Because units -002 and-003 share a common stack with units -004 and -005, visible emissions violations from the stack will be attributed to all five units unless opacity meter results show the specific unit causing the violation.
[Rule 62-296.405(1)(a), F.A.C.; and, AO17-249656, Specific Condition 8.]

A.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

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

{Permitting Note: Load changes may be demonstrated by monitoring megawatt output.}

A.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

{Permitting Note: The averaging time shall correspond to the cumulative sample time, as specified in the reference test method (see Specific Condition **A.18.**).}

A.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

A.9. Sulfur Dioxide - Liquid Fuel. When burning liquid fuel, sulfur dioxide emissions shall not exceed 1.98 pounds per million Btu heat input , as measured by applicable compliance methods.
[Rule 62-296.405(1)(c)1.e., F.A.C.]

A.10. Sulfur Dioxide - Sulfur Content. In order to ensure continuous compliance with the liquid fuel sulfur limit specified in Specific Condition **A.9.**, the liquid fuel sulfur content shall not exceed 1.8 percent, by weight, as measured by applicable test methods.
[Rule 62-213.440, F.A.C.; and, Applicant's Request.]

Excess Emissions

A.11. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

A.12. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

A.13. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

A.14. Sulfur Dioxide. Those emissions units not having an operating flue gas desulfurization device may monitor sulfur dioxide emissions by fuel sampling and analysis according to methods approved by the EPA. **Compliance with the liquid fuel sulfur limit will be verified by performing a daily, as-fired, fuel analysis.** This protocol is allowed because these emissions units do not have operating flue gas desulfurization devices. See Specific Conditions **A.10. and A.20.** of this permit.
[Rule 62-296.405(1)(f)1.b., F.A.C.; and, applicant request.]

Required Tests, Test Methods and Procedures

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

A.15. Annual Tests Required. Except as provided in Specific Conditions **A.28. – 30.**, units -002 and -003 shall conduct annual testing for particulate matter and visible emissions in accordance with the requirements listed below.
[Rule 62-297.310(7)(a)4., F.A.C.]

A.16. Visible Emissions. The test method for visible emissions shall be DEP Method 9 (see Specific Condition **A.17.**), incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.]

A.17. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rules 62-297.310 and 62-297.401, F.A.C.]

A.18. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310, and 62-297.401, F.A.C.]

A.19. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-

297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by this permit, the permittee elected to demonstrate compliance by performing a daily, as-fired, fuel analysis.** See Specific Conditions **A.10. and A.20.**
[Rules 62-213.440, 62-296.405(1)(e)3., 62-297.310 and 62-297.401, F.A.C.]

A.20. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.21. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
    a. Did not operate; or
    b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
    a. Visible emissions, if there is an applicable standard (see Specific Condition **A.28.**);
    b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
    c. Each NESHAP pollutant, if there is an applicable emission standard.
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test

contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

[Rule 62-297.310(7), F.A.C.; and SIP Approved]

Compliance Test Requirements

A.22. Determination of Process Variables.

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

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

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

A.23. Determination of Compliance with Permitted Capacity: Compliance with the above heat input limitations (see Specific Condition **A.1.**) shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel. Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

ACID RAIN

{Permitting Note: The permittee and the Department agree that the CEMS ~~used~~ for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

A.24. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

A.25. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

A.26. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

A.27. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
   a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
   b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

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

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

{Permitting Note: Specific Condition A.18. specifies a minimum sample volume of 30 dry standard cubic feet.}

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

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

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings
		Max. deviation between readings	.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

A.28. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

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

[Rule 62-297.310(7)(a)4., F.A.C.]

A.29. Particulate Matter Testing - Annual. Annual compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s), other that during startup, for no more than 400 hours per year,; or,
c. only liquid fuel(s), other that during startup, for no more than 400 hours per year.

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

A.30. Particulate Matter Testing - Permit Renewal. Permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for no more than 400 hours per year; or,
c. only liquid fuel(s) for no more than 400 hours per year.

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

Recordkeeping and Reporting Requirements

A.31. The owner or operator shall maintain daily records of fuel consumption and each analysis that provides the heating value and sulfur content for all fuels fired. These records must be of sufficient detail to determine compliance with the conditions of this permit.
[Rules 62-213.440 and 62-4.070(3), F.A.C.]

A.32. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

A.33. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

A.34. 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 on the results of each such test.
(b) The required test report shall be filed with the Department 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 to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

<u>Miscellaneous Conditions</u>.

A.35. <u>Used Oil</u>. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power, not to exceed 10,000 gallons per calendar year in each boiler (units -002 & -003).

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Requirements: For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

   The requirements of this demonstration are governed by the following federal regulations:

   Analysis of used oil fuel. A generator, transporter, processor/re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications.
   [40 CFR 279.72(a)]

   Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.
   (i) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.
   (ii) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater

have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.

(iii) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see Specific Condition **A.20.**).

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
(1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and
(2) For each deposit of used oil, results of the analyses as required by the above conditions, or
(3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above, the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

A.36. Common Conditions. These emissions units are also subject to the conditions in Subsection E.
[0330045-005-AC]

Subsection B. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-004	Boiler Number 4 (Substitution Phase I Acid Rain Unit)
-005	Boiler Number 5 (Substitution Phase I Acid Rain Unit)

Emissions unit number -004 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 4". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Emissions unit number -005 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 5". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Both units are Phase I Substitution and Phase II Acid Rain Units.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase I and Phase II. These emissions units pre-date PSD regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from units -004 and -005 are controlled by hot side (Buell Model # Bal. 2x34n333-4-3p) and cold side (Buell Model # 1.1x48k33-1p) electrostatic precipitators. Unit -004 began commercial operation on July 1, 1959. Unit -005 began commercial operation on June 1, 1961. The generator nameplate rating for unit -004 is 93 MW. The generator nameplate rating for unit -005 is 93 MW. Units -004 and -005 share a common stack with units -002 and -003. Stack height = 450 feet, exit diameter = 18.0 feet, exit temperature = 290 °F, actual volumetric flow rate = 802,500 acfm.}

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
-004	1,096.7	Coal
	1,096.7	Natural Gas
	1,096.7	No. 2 Fuel Oil
	1,096.7	On-Specification Used Oil
-005	1,096.7	Coal
	1,096.7	Natural Gas
	1,096.7	No. 2 Fuel Oil
	1,096.7	On-Specification Used Oil

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), 62-214.330 & 62-296.405, F.A.C.; and, permits AC17-2126, AC17-2127 & 0330045-010-AC.]

B.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **B.31.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation.

a. Fuels. The fuels that are allowed to be burned in these boilers are coal, natural gas, new No. 2 fuel oil and/or on-specification used oil (see Specific Condition **B.38.**). Fuel oil is only used for periods of start-up and as needed for flame stabilization. Also, on-site generated "oil contaminated soil" is periodically combusted for energy recovery purposes.

b. Other.
   i. Supplemental injection of "GAM 60" for purposes of maintaining boiler tube temperatures.
   ii. Supplemental injection of sodium carbonate or sodium sulfate at a rate of 440 pounds per hour as necessary to enhance the operation of the particulate control devices on these units

[Rule 62-213.410, F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

B.4. Hours of Operation. These emissions units may operate continuously, i.e. 8760 hours/year. For each emissions unit, the permittee shall maintain a daily operations log available for Department inspection that documents the total hours of annual operation, including an account of the hours operated on each of the allowable fuels.
[Rules 62-213.440 and 62-210.200(PTE), F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

Emission Limitations and Standards

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

{Permitting Note: Unless otherwise specified, the averaging times for Specific Conditions **B.5.-B.10.** are based on the specified averaging time of the applicable test method.}

B.5. Visible Emissions. Visible emissions shall not exceed 40 percent opacity. Because units -004 and -005 share a common stack with units -002 and -003, visible emissions violations from the stack will be attributed to all five units unless opacity meter results show the specific unit causing the violation.
[Rule 62-296.405(1)(a), F.A.C.; and, Secretarial ORDER(s) signed October 18, 1985 & January 3, 1986; and, AO17-211303, Specific Condition 10.]

B.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed for boiler cleaning and load changes, at units which have installed continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

{Permitting Note: Load changes may be demonstrated by monitoring megawatt output.}

B.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

B.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

B.9. Sulfur Dioxide - Solid Fuel. When burning solid fuel, sulfur dioxide emissions shall not exceed 5.90 pounds per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(c)2.c., F.A.C.]

B.10. Sulfur Dioxide - Liquid Fuel. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.40 pounds per million Btu heat input , as measured by applicable compliance methods.
[0330045-010-AC]

B.11. Sulfur Dioxide - Sulfur Content. In order to ensure continuous compliance with the liquid fuel sulfur limit specified in Specific Condition **B.10.**, the liquid fuel sulfur content shall not exceed 2.18 percent, by weight, as measured by applicable test methods.
[Rule 62-213.440, F.A.C.]

Excess Emissions

B.12. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

B.13. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

B.14. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

{Permitting Note: In accordance with the Acid Rain Phase II requirements, the following continuous monitors are installed on these units: SO_2, NO_X, CO_2 and stack gas flow.}

B.15. Continuous Monitors. For these emissions units, the permittee shall calibrate, operate and maintain continuous emissions monitoring systems (CEMS) for monitoring opacity, SO_2 and CO_2.
[Rule 62-296.405(1)(f)1., F.A.C.; and, Permit AO17-211303.]

B.16. Sulfur Dioxide. Those emissions units not having an operating flue gas desulfurization device may monitor sulfur dioxide emissions by fuel sampling and analysis according to methods approved by the EPA. **The permittee elected to satisfy the monitoring requirements using SO_2 continuous emissions monitors.**
[Rule 62-296.405(1)(f)1.b., F.A.C.; and, Applicant request.]

Required Tests, Test Methods and Procedures

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

B.17. Annual Tests Required. Units -004 and -005 shall be tested annually for SO_2 and PM emissions in accordance with the requirements listed below.
[Rule 62-297.310(7)(a)4., F.A.C.]

{Permitting Note: The annual SO_2 test that is required by Rule 62-297.310(7), F.A.C., can be done during the annual RATA as satisfaction of this requirement, provided all other testing requirements specified in the permit are met.}

B.18. Testing While Injecting Additives. The owner or operator shall conduct all emissions tests while injecting additives consistent with normal operating practices approved by the Department.
[Rule 62-213.440, F.A.C.]

B.19. Visible Emissions. The test method for visible emissions shall be DEP Method 9 (see Specific Condition **B.20.**), incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. **The permittee has elected to utilize a transmissometer (opacity meter) for demonstrating compliance with the visible emissions limit.** As long as the transmissometer is calibrated, maintained, and operated in accordance with Performance Specification 1 of 40 CFR 60, Appendix B (see Specific Condition **B.24.**), the annual test for visible emissions is not required.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

{Permitting Note: A transmissometer used to demonstrate compliance should record sufficient data so as to be equivalent to a Method 9 test. Method 9 requires determining an average based on 24 readings at 15-second intervals, thus, a six-minute average. The transmissometers in use at this facility make a permanent recording every six-minutes based on an average of readings taken every 15 seconds. After the 6-minute average is recorded, the individual readings are erased and a new 6-minute average is determined based on the next set of 24 individual readings. This 6-minute block recording is consistent with the requirements of Method 9.}

B.20. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rules 62-297.310 and 62-297.401, F.A.C.]

B.21. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310, and 62-297.401, F.A.C.]

B.22. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-297.310, and 62-297.401, F.A.C.; and, AO17-211303.]

{Permitting Note: The permittee has elected to demonstrate compliance by means of a continuous emissions monitoring system (CEMS). In addition to any other requirements associated with the operation and maintenance of these CEMS (i.e., Acid Rain requirements), operation of the CEMS shall be in accordance with the requirements listed below. The annual calibration RATA associated with these CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the

requirements of Rule 62-297.310, F.A.C., are met (i.e., prior test notification, proper test result submittal, etc.).}

B.23. Continuous SO_2 emission monitoring 24-hour averages are required to demonstrate compliance with the standards of the Department (see Specific Conditions **B.9. - B.11.**). A valid 24-hour average shall consists of no less than 18 hours of valid data capture per calendar day. In the event that valid data capture is interrupted, the permittee shall initiate as-fired fuel sampling to demonstrate compliance with the SO_2 emissions standard. The as-fired fuel sampling shall be initiated no later than 36 hours after the permittee has verified the problem or no later than 36 hours after the end of the affected calendar day. As-fired fuel sampling shall continue until such time as valid data capture is restored. In lieu of as-fired fuel sampling, the permittee may elect to demonstrate SO_2 emissions compliance by the temporary use of a spare SO_2 emissions monitor. The spare, previously calibrated, SO_2 emissions monitor must be installed and collecting data in the same time frame as required above for as-fired fuel sampling.

A quality control (QC) program must be maintained. At a minimum, the QC program must include written procedures which shall describe in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS.
2. Calibration Drift (CD) determination and adjustment of CEMS.
3. Preventative maintenance of CEMS (including spare parts inventory).
4. Data recording, calculations and reporting.
5. Accuracy audit procedures including sampling and analysis methods.
6. Program of corrective action for malfunctioning CEMS.

[Rules 62-213.440, 62-204.800(7)(e)5. and 62-296.405(1)(f)1.b., F.A.C.; and, AO17-211303.]

B.24. Continuous Monitor Performance Specifications. If continuous monitoring systems are required by rule or are elected by the permittee to be used for demonstrating compliance with the standards of the Department, they must be installed, maintained and calibrated, either:

(a) in accordance with the EPA performance specifications listed below. These Performance Specifications are contained in 40 CFR 60, Appendix B, and are adopted by reference in Rule 62-204.800, F.A.C.
   (1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.
   (2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources.
   (3) Performance Specification 3--Specifications and Test Procedures for CO_2 Continuous Emission Monitoring Systems in Stationary Sources. Or,

(b) in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Excess emissions pursuant to Rule 62-210.700, F.A.C., shall be determined using the 40 CFR part 75 CEMS.

[Rule 62-297.520, F.A.C.; 40 CFR 75; and, Applicant request.]

B.25. Fuel Sampling and Analysis. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard in the event that the SO_2 continuous emissions monitor is not able to capture valid data:

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

b. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using ASTM D2013-72 and either ASTM D3177-75 or ASTM D4239-85, or the latest edition, to analyze a representative sample of the blended as-fired pulverized coal.
c. Determine and record the density (using ASTM D 1298-80, or equivalent) and the calorific heat value in Btu per pound (using ASTM D 240-76, or the latest edition) of the fuel oil combusted.
d. Determine and record the calorific heat value in Btu per pound of the blended, as-fired pulverized coal using ASTM D2013-72 and either ASTM D2015-77 or D3286-(latest version), or the latest edition.
e. Record daily the amount of each fuel fired, the density of the fuel oil, the heating value of each fuel fired, and the percent sulfur content, by weight, of each fuel fired.
f. Utilize the information in a., b., c., d. and e., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

B.26. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
    a. Did not operate; or
    b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
    a. Visible emissions, if there is an applicable standard;
    b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
    c. Each NESHAP pollutant, if there is an applicable emission standard.
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test

contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

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

Compliance Test Requirements

B.27. Determination of Process Variables.

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

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

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

B.28. Determination of Compliance with Permitted Capacity. Compliance with the above heat input limitations (see Specific Condition **B.1.**) shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **B.25.d.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.

[0330045-010-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

B.29. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to

this permit.
[Rule 62-297.310(6), F.A.C.]

B.30. 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.31. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

B.32. Applicable Test Procedures.
(a) Required Sampling Time.
  1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
  2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
     a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
     b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

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

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

{Permitting Note: Specific Condition **B.21.** specifies a minimum sample volume of 30 dry standard cubic feet.}

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

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

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass	+/-2% ref. thermometer or equivalent, or thermometric points
Bimetallic thermometer	Quarterly	Calib. liq. in	5 degrees F glass thermometer
Thermocouple	Annually	ASTM Hg in glass	5 degrees F ref. thermometer, NBS calibrated reference and potentiometer
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

Recordkeeping and Reporting Requirements

B.33. The owner or operator shall maintain daily records of all fuels consumed.
[Rules 62-213.440 & 62-4.070(3), F.A.C.]

B.34. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

B.35. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

B.36. A maintenance log of the continuous monitoring systems shall be kept showing the following:

a. Time out of service.
b. Calibration and adjustments.

[Rule 62-213.440, F.A.C.; and, AO17-211303, Specific Condition 8.]

B.37. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department 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 to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
   1. The type, location, and designation of the emissions unit tested.
   2. The facility at which the emissions unit is located.
   3. The owner or operator of the emissions unit.
   4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
   5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
   6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
   7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
   8. The date, starting time and duration of each sampling run.
   9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
   10. The number of points sampled and configuration and location of the sampling plane.

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

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

Miscellaneous Conditions.

B.38. Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power Company, not to exceed 50,000 gallons per calendar year in each boiler (-004 & -005).

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Requirements: For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel. A generator, transporter, processor/re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications.
[40 CFR 279.72(a)]

Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(i) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.
(ii) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.
(iii) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see Specific Condition **B.25.**).

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
   (1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and
   (2) For each deposit of used oil, results of the analyses as required by the above conditions, or
   (3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above and the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

B.39. Compliance Assurance Monitoring: These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C.
[40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

B.40. Common Conditions. These emissions units are also subject to the conditions in Subsection E.
[0330045-005-AC]

Subsection C. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-006	Boiler Number 6 (Phase I Acid Rain Unit)
-007	Boiler Number 7 (Phase I Acid Rain Unit)

Emissions unit number -006 is a Foster Wheeler front wall fired, dry bottom boiler designated as "Boiler Number 6". It is rated at a maximum heat input of 3,704.8 million Btu per hour (MMBtu/hour) when firing pulverized coal and/or natural gas. Emissions unit number -007 is a Foster Wheeler front and rear wall fired, dry bottom boiler designated as "Boiler Number 7". It is rated at a maximum heat input of 6,406.4 million Btu per hour (MMBtu/hour) when firing pulverized coal and/or natural gas. Fuel oil is used as a back-up fuel in both units and for periods of start-up and flame stabilization.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase I. These emissions units pre-date PSD regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. Particulate matter emissions from unit -006 are controlled by a cold side electrostatic precipitator (Wheelabrator Model # HaRDE). Particulate matter emissions from unit -007 are controlled by cold side electrostatic precipitators designed by Alstom Power Inc. NO_X emissions from units -006 are controlled by Foster Wheeler Low NO_X Burners. NO_X emissions from unit -007 are controlled by Foster Wheeler Low NO_X Burners and by an SCR system designed to achieve no less than an 85% reduction in NO_X emissions as measured across the SCR unit inlet and outlet. The designed target ammonia slip level is 5 ppmv based on a 24-hour average. Unit -006 began commercial operation on May 1, 1970. Unit -007 began commercial operation on August 1, 1973. Units -006 and -007 share a common stack. Stack height = 450 feet, exit diameter = 23.2 feet, exit temperature = 320 °F, actual volumetric flow rate = 2,462,700 acfm.}

MAXIMUM?

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
-006	3,704.8	Coal
	3,704.8	Natural Gas
	714.8	No. 2 Fuel Oil
	714.8	On-Specification Used Oil
-007	6,406.4	Coal
	6,406.4	Natural Gas
	1,282	No. 2 Fuel Oil
	1,282	On-Specification Used Oil

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), 62-214.330 & 62-296.405, F.A.C.; and, permits AC17-2126, AC17-2127 & 0330045-010-AC.]

C.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.39.**
[Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation.

a. Fuels. The fuels that are allowed to be burned in these boilers are coal, natural gas, new No. 2 fuel oil and/or on-specification used oil (see Specific Condition **C.48.**). Fuel oil is only used for periods of start-up and as needed for flame stabilization. Also, on-site generated "oil contaminated soil" is periodically combusted for energy recovery purposes.

b. Other.
   1. Supplemental injection of ammonia at a rate of 25 to 40 pounds per hour.
   2. Supplemental injection of sulfur trioxide at a rate of 4 to 20 ppm.
   3. Supplemental injection of "GAM 60" for purposes of maintaining boiler tube temperatures.

[Rule 62-213.410, F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

C.4. Hours of Operation. These emissions units may operate continuously, i.e. 8760 hours/year. For each emissions unit, the permittee shall maintain a daily operations log available for Department inspection that documents the total hours of annual operation, including an account of the hours operated on each of the allowable fuels.
[Rules 62-213.440 and 62-210.200(PTE), F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

Emission Limitations and Standards

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

{Permitting Note: Unless otherwise specified, the averaging times for Specific Conditions **C.5.-C.12.** are based on the specified averaging time of the applicable test method.}

C.5. Visible Emissions. Visible emissions from unit -006 shall not exceed 40 percent opacity. Visible emissions from unit -007 shall not exceed 20% based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27%. Because units -006 and -007 share a common stack, visible emissions violations from the stack will be attributed to both units unless opacity meter results show the specific unit causing the violation.
[Rule 62-296.405(1)(a), F.A.C.; and, Secretarial ORDER(s) signed May 12, 1988 & June 24, 1988; and, permits AC17-2234016, Specific Condition 14, AO17- 171806, Specific Condition 23 & 0330045-005-AC.]

C.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed for boiler cleaning and load changes, at units which have installed continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

{Permitting Note: Load changes may be demonstrated by monitoring megawatt output.}

C.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods. Particulate matter emissions from unit 6 shall not exceed 1,475 tons per year.
[Rule 62-296.405(1)(b), F.A.C.; and, AC17-234016.]

C.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

C.9. Sulfur Dioxide - Solid Fuel. When burning solid fuel, sulfur dioxide emissions shall not exceed 2.40 pounds per million Btu heat input, as measured by applicable compliance methods. When burning solid fuel, sulfur dioxide emissions from unit 6 shall not exceed 38,945 tons per year.
[Rule 62-296.405(1)(c)2.c., F.A.C.; and, 0330045-008-AC.]

C.10. Sulfur Dioxide - Liquid Fuel. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.40 pounds per million Btu heat input , as measured by applicable compliance methods.
[0330045-010-AC]

C.11. Sulfur Dioxide - Sulfur Content. In order to ensure continuous compliance with the liquid fuel sulfur limit specified in Specific Condition **C.10.**, the liquid fuel sulfur content shall not exceed 2.18 percent, by weight, as measured by applicable test methods.
[Rule 62-213.440, F.A.C.]

C.12. Nitrogen Oxides.
a. (Interim). Prior to implementing the required NO_X control strategy for Units -004, -005 and -006, the NO_X emissions from Unit -007 shall not exceed 0.15 lb/MMBtu of heat input based on a 30-day rolling average when the SCR system is operational with a catalyst temperature of at least 600° F. The permittee shall demonstrate compliance with data collected from the certified CEMS.
b. Permanent. After the required NO_X control strategy is implemented for Units -004, -005, and -006, the plant-wide NO_X standard specified in Subsection E. shall supersede this interim standard.
[0330045-005-AC]

Excess Emissions

C.13. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

C.14. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

C.15. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

SCR Operation

MAXIMUM ?

C.16. Selective Catalytic Reduction (SCR) System: The permittee shall operate and maintain an SCR system for Unit -007 to reduce emissions of nitrogen oxides (NO_X) as described in the application, approved drawings, plans, and other documents on file with the Department. The SCR system shall be designed to achieve no less than an 85% reduction in NO_X emissions as measured across the SCR unit inlet and outlet. The designed target ammonia slip level is 5 ppmv based on a 24-hour average. The storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[0330045-005-AC]

SCR Bypass Operation

C.17. SCR Bypass, Startup/Shutdown: During Unit -007 startup and shutdown, the SCR system may be bypassed in accordance with manufacturer's recommended procedures to allow for controlled catalyst heating and cooling. During startup, the SCR system shall be on line and functioning when the minimum operating temperature of the catalyst is achieved (≥ 600° F). During shutdown, the SCR system may be removed from service when the catalyst temperature drops below 600° F.
[Design; Rule 62-210.700, F.A.C. ; and, 0330045-005-AC.]

C.18. SCR Bypass, Catalyst Maintenance and Repair: The permittee may bypass the SCR system to perform catalyst maintenance and repair for up to 15 days per year during the non-ozone season. During such allowable bypass periods, the uncontrolled NO_X emissions from Unit -007 shall not exceed 0.35 lb/MMBtu based on a 24-hour average. The daily NO_X emission rates for these periods may be excluded from the plant-wide 30-day NO_X standard specified in Specific Condition **E.2.** The permittee shall notify the Compliance Authority in advance of the purpose of the SCR bypass, the expected dates of SCR bypass, and the expected duration of SCR bypass.
[Rules 62-210.700 and 62-4.070(3), F.A.C.; and, 0330045-005-AC.]

{Permitting Note: The ozone season is defined as May 1st through September 15th.}

Monitoring of Operations

{Permitting Note: In accordance with the Acid Rain Phase II requirements, the following continuous monitors are installed on these units: SO_2, NO_X, CO_2 and stack gas flow.}

C.19. Continuous Monitors. For these emissions units, the permittee shall calibrate, operate and maintain continuous monitoring systems for monitoring opacity, SO_2, NO_X and CO_2.

[Rule 62-296.405(1)(f)1., F.A.C.; and, Permits AC17-234016, AO17-171806 & 0330045-005-AC.]

C.20. COMS. The permittee shall install, calibrate, operate and maintain a continuous opacity monitoring system (COMS) to demonstrate compliance with the stack opacity standard. The COMS shall monitor and record data during all periods of Unit -007 operation including startup, shutdown, malfunction or emergency conditions, but not including continuous monitoring system breakdowns, repairs, or calibration checks.
[0330045-005-AC]

{Permitting Note: The existing COMS required by the Acid Rain program satisfies this requirement.}

C.21. NO_X CEMS. To demonstrate compliance with the emissions standards, the permittee shall install, calibrate, operate and maintain a continuous emissions monitoring system (CEMS) to continuously monitor and record the emissions of nitrogen oxides and an appropriate diluent gas (carbon dioxide or oxygen). The CEMS shall monitor and record data during all periods of Unit -007 operation including startup, shutdown, malfunction or emergency conditions, but not including continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments. For each calendar quarter, monitor availability shall be 95% or greater. If unable to achieve this level, the permittee shall submit a report identifying the problems in achieving 95% monitor availability and a plan of corrective actions. The permittee shall implement the reported corrective actions within the next calendar quarter.
[0330045-005-AC]

{Permitting Note: The existing NO_X CEMS required by the Acid Rain program satisfies this requirement.}

C.22. Sulfur Dioxide. Those emissions units not having an operating flue gas desulfurization device may monitor sulfur dioxide emissions by fuel sampling and analysis according to methods approved by the EPA. **The permittee elected to satisfy the monitoring requirements using SO_2 continuous emissions monitors.**
[Rule 62-296.405(1)(f)1.b., F.A.C.; Permits AC17-234016 & AO17-171806; and, Applicant request.]

Required Tests, Test Methods and Procedures

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

C.23. Annual Tests Required. Units -006 and -007 shall be tested annually for NO_X, SO_2, PM and ammonia slip emissions in accordance with the requirements listed below.
[Rule 62-297.310(7)(a)4., F.A.C.; and, 0330045-005-AC]

{Permitting Note: The annual SO_2 test that is required by Rule 62-297.310(7), F.A.C., can be done during the annual RATA as satisfaction of this requirement, provided all other testing requirements specified in the permit are met.}

C.24. Testing While Injecting Additives. The owner or operator shall conduct all emissions tests while injecting additives consistent with normal operating practices approved by the Department.
[Rule 62-213.440, F.A.C.]

C.25. Visible Emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. **The permittee has elected to utilize a transmissometer (opacity meter) for demonstrating compliance with the visible emissions limit**. As long as the transmissometer is calibrated, maintained, and operated in accordance with Performance Specification 1 of 40 CFR 60, Appendix B (see Specific Condition **C.32.**), the annual test for visible emissions is not required.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.; and, Applicant's request in Title V permit renewal application received June 22, 2004.]

{Permitting Note: A transmissometer used to demonstrate compliance should record sufficient data so as to be equivalent to a Method 9 test. Method 9 requires determining an average based on 24 readings at 15-second intervals, thus, a six-minute average. The transmissometers in use at this facility make a permanent recording every six-minutes based on an average of readings taken every 15 seconds. After the 6-minute average is recorded, the individual readings are erased and a new 6-minute average is determined based on the next set of 24 individual readings. This 6-minute block recording is consistent with the requirements of Method 9.}

C.26. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rules 62-297.310 and 62-297.401, F.A.C.]

C.27. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be

30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310, and 62-297.401, F.A.C.]

C.28. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards.
[Rules 62-213.440, 62-296.405(1)(e)3. 62-297.310 and 62-297.401, F.A.C.; and, Permits AC17-234016 and AO17-171806.]

{Permitting Note: The permittee has elected to demonstrate compliance by means of a continuous emissions monitoring system (CEMS). In addition to any other requirements associated with the operation and maintenance of these CEMS (i.e., Acid Rain requirements), operation of the CEMS shall be in accordance with the requirements listed below. The annual calibration RATA associated with these CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the requirements of Rule 62-297.310, F.A.C., are met (i.e., prior test notification, proper test result submittal, etc.).}

C.29. Continuous SO_2 emission monitoring 24-hour averages are required to demonstrate compliance with the standards of the Department (see Specific Conditions **C.9. - C.11.**). A valid 24-hour average shall consist of no less than 18 hours of valid data capture per calendar day. In the event that valid data capture is not available, the permittee shall initiate as-fired fuel sampling to demonstrate compliance with the SO_2 emissions standard. The as-fired fuel sampling shall be initiated no later than 36 hours after the permittee has verified the problem or no later than 36 hours after the end of the affected calendar day. Fuel sampling shall continue until such time as the valid data capture is restored. In lieu of as-fired fuel sampling the permittee may elect to demonstrate SO_2 emissions compliance by the temporary use of a spare SO_2 emissions monitor. The spare SO_2 emissions monitor must be installed and collecting data in the same time frame as required above for as-fired fuel sampling.

Maintain a QC program. At a minimum, the QC program must include written procedures which shall describe in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS.
2. Calibration Drift (CD) determination and adjustment of CEMS.
3. Preventative maintenance of CEMS (including spare parts inventory).
4. Data recording, calculations and reporting.
5. Accuracy audit procedures including sampling-and analysis methods.
6. Program of corrective action for malfunctioning CEMS.

[Rules 62-213.440, 62-204.800(7)(e)5., and 62-296.405(1)(f)1.b., F.A.C.; and, Permits AC17-234016 and AO17-171806.]

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C.30. Nitrogen Oxides, Compliance Tests. During each federal fiscal year (October 1st to September 30th), the permittee shall conduct tests to demonstrate compliance the emission limits contained in Specific Condition C.12. and with the design specification to achieve no less than an 85% reduction in the nitrogen oxide emission rate. The permittee shall concurrently test the SCR inlet and SCR outlet in accordance with EPA Method 7E as adopted by reference in Rule 62-204.800, F.A.C. Data collected during the annual NO_X RATA testing may be used to represent NO_X emissions at the SCR outlet. Alternatively, the permittee may submit data collected from the NO_X rate process monitors at the SCR inlet and SCR outlet, which are part of the ammonia injection system. The data shall be collected for at least three consecutive hours.
[Rules 62-4.070(3) & 62-297.310(7), F.A.C.; and, 0330045-005-AC.]

C.31. Ammonia Slip, Performance Tests. During each federal fiscal year, the permittee shall conduct tests to determine the ammonia slip rate in accordance with EPA Method CTM-027 or other methods approved by EPA. If tests show ammonia slip emissions are greater than the design target level specified in Specific Condition **C.16.** of this subsection, the permittee shall take corrective actions such as repair, addition of catalyst, replacement of catalyst, etc.
[Rules 62-4.070(3) & 62-297.310(7), F.A.C.; and, 0330045-005-AC.]

C.32. Continuous Monitor Performance Specifications. If continuous monitoring systems are required by rule or are elected by the permittee to be used for demonstrating compliance with the standards of the Department, they must be installed, maintained and calibrated, either:

(a) in accordance with the EPA performance specifications listed below. These Performance Specifications are contained in 40 CFR 60, Appendix B, and are adopted by reference in Rule 62-204.800, F.A.C.
   (1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.
   (2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources.
   (3) Performance Specification 3--Specifications and Test Procedures for CO_2 Continuous Emission Monitoring Systems in Stationary Sources. Or,

(b) in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Excess emissions pursuant to Rule 62-210.700, F.A.C., shall be determined using the 40 CFR part 75 CEMS.

[Rule 62-297.520, F.A.C.; 40 CFR 75; and, Applicant request.]

C.33. Fuel Sampling and Analysis. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard in the event that the SO_2 continuous emissions monitor is not able to capture valid data:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, to analyze a representative sample of the blended fuel following each fuel delivery.
b. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using ASTM D2013-72 and either ASTM D3177-75 or ASTM D4239-85, or the latest edition, to analyze a representative sample of the blended as-fired pulverized coal.
c. Determine and record the density (using ASTM D 1298-80, or equivalent) and the calorific heat value in Btu per pound (using ASTM D 240-76, or the latest edition) of the fuel oil combusted.

d. Determine and record the calorific heat value in Btu per pound of the blended, as-fired pulverized coal using ASTM D2013-72 and either ASTM D2015-77 or D3286-(latest version), or the latest edition.
e. Record daily the amount of each fuel fired, the density of the fuel oil, the heating value of each fuel fired, and the percent sulfur content, by weight, of each fuel fired.
f. Utilize the information in a., b., c., d. and e., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

C.34. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   c. Each NESHAP pollutant, if there is an applicable emission standard.
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

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

Compliance Test Requirements

C.35.. Determination of Process Variables.

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

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

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

C.36. Determination of Compliance with Permitted Capacity. Compliance with the above heat input limitations (see Specific Condition **C.1.**) shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **C.33.d.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.

[0330045-010-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

C.37. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.

[Rule 62-297.310(6), F.A.C.]

C.38. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured

provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

C.39. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

C.40. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
   a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
   b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
   c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

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

{Permitting Note: Specific Condition C.21. specifies a minimum sample volume of 30 dry standard cubic feet.}

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

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

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass	+/-2% ref. thermometer or equivalent, or thermometric points
Bimetallic thermometer	Quarterly	Calib. liq. in	5 degrees F glass thermometer
Thermocouple	Annually	ASTM Hg in glass	5 degrees F ref. thermometer, NBS calibrated reference and potentiometer
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

Recordkeeping and Reporting Requirements

C.41. The owner or operator shall maintain daily records of all fuels consumed.
[Rules 62-213.440 and 62-4.070(3), F.A.C.]

C.42. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

C.43. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

C.44. A maintenance log of the continuous monitoring systems shall be kept showing the following:
a. Time out of service.
b. Calibration and adjustments.

[Rule 62-213.440, F.A.C.; and, Permits AC17-234016 & AO17-171806.]

C.45. 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 on the results of each such test.
(b) The required test report shall be filed with the Department 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 to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.

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

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

C.46. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the provisions of Rule 62-297.310(8), F.A.C. For each required test run, the report shall indicate the actual heat input rate (MMBtu/hour), the NO_X emission rate (lb/MMBtu) as recorded by the CEMS, and the ammonia injection rate (lb/hour). The report shall also include copies of the continuous monitoring records for opacity and NO_X emissions.
[Rule 62-297.310(8), F.A.C.; and, 0330045-005-AC.]

C.47. Quarterly Report

a. NO_X Summary. For each calendar day during the reporting quarter, the permittee shall report the following information related to the NO_X CEMS for Unit -007:
   1. Hours of operation for Unit -007;
   2. Daily average NO_X emission rate, lb/MMBtu;
   3. 30-day average NO_X emission rate, lb/MMBtu; and
   4. Whether or not the day included a startup, shutdown, malfunction or bypass of the SCR.

   Identify the "F" factor used for any calculations, the method of determination, and type of fuel combusted. For each day that CEMS data was not obtained for at least 18 hours of Unit 7 operation, provide a justification for not obtaining sufficient data and describe the corrective actions taken to prevent this in the future. Identify any emissions data excluded from the calculation of emission rates due to startup, shutdown, or malfunction.

b. Opacity Summary. For each calendar day during the reporting quarter, the permittee shall report each 6-minute period in excess of the opacity standard.

c. Gas Sampling Grid (GSG). The permittee shall summarize any tests using the GSG that were conducted during the calendar quarter.

Each quarterly report is due within 30 days of the calendar quarter being reported. [0330045-005-AC]

Miscellaneous Conditions.

C.48. Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power Company, not to exceed 50,000 gallons per calendar year in each boiler (-006 & -007).

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Requirements: For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel. A generator, transporter, processor/ re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications.
[40 CFR 279.72(a)]

Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(i) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.

(ii) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.

(iii) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see Specific Condition **C.25.**).

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:

(1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and

(2) For each deposit of used oil, results of the analyses as required by the above conditions, or

(3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above and the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

C.49. Compliance Assurance Monitoring. These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C.
[40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

C.50. Common Conditions. These emissions units are also subject to the conditions in Subsection E.
[0330045-005-AC]

Subsection D. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-008	Fly Ash Storage Silos (2)

This emissions unit consists of two Fly Ash Storage Silos. The fly ash collection systems from the precipitators on boilers numbers 4, 5, 6 & 7 to the three transfer tanks are totally enclosed (i.e. no emission points). Three blowers pneumatically convey dry fly ash to 2 silos at a maximum solids rate of 150 tons per hour to either silo or to both. The majority of the solids (99.4%) settles by gravity upon entering the silo and the residual particulates are controlled by a baghouse on each silo. Each baghouse is a Pulse Jet Fabric Filter - model #100 - WMWC - 420 (IIG) manufactured by Flex-Kleen. Dry fly ash will be transported off-site in closed tanker trucks (approximately 20% sold annually) or conditioned fly ash (12-15% water added) will be transported to an approved landfill area on-site.

{Permitting notes: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required, and Rule 62-296.320, F.A.C., General Pollutant Emission Limiting Standards. There is one baghouse on each silo. Each silo has two vents. Stack height = 124.5 feet, exit dimensions = 18" x 24" rectangle, exit temperature = 100 °F, actual volumetric flow rate = 5,452 acfm per vent, velocity = 30 feet per second. The two silos were built between October 27, 1981 and June 1, 1983.}

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

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum operating rate is as follows:

Unit No.	Operating Rate
-008	150 Tons Per Hour of Fly Ash Transported to Either or Both Silos

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AC17-47675.]

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

D.3. Hours of Operation. Each fly ash storage silo may operate continuously, i.e. 8,760 hours per year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

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

D.4. Visible Emissions. Visible emissions from each baghouse vent (2 on each baghouse) shall be less than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AC17-47675.]

Excess Emissions

D.5. Excess emissions from this emissions unit resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

D.6. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Required Tests, Test Methods and Procedures

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

D.7. Annual Tests Required. Unit -008 must be tested annually for visible emissions in accordance with the requirements listed below.

D.8. Visible emissions. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

D.9. **Not federally enforceable.** Operating Rate During Testing. Compliance shall be demonstrated at an operating rate which typifies normal operation of the fly ash system. This operating rate may be lower than the maximum allowable operating rate. Should the Department feel that test results do not provide reasonable assurance that the source is capable of compliance at the permitted maximum operating rate, the Department may request that a visible emissions test be conducted at a higher operating rate up to the maximum allowable operating rate.
[January 16, 1984 letter modifying permit AO17-70422, Specific Condition 15.]

D.10. Applicable Test Procedures.
(a) Required Sampling Time.
  2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
    c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2., F.A.C.]

D.11. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

[Rule 62-297.310(7), F.A.C.; and, SIP Approved.]

Recordkeeping and Reporting Requirements

D.12. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

D.13. Test Reports.

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

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

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

Subsection E. This section addresses the following emissions units.

This section of the permit addresses the following emissions units.

E.U. ID No.	**Brief Description**
-001	Boiler Number 1 - 420 MMBtu/hour (retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hour **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hour **(to be retired by May 1, 2006)**
-004	Boiler Number 4 - 1,096.7 MMBtu/hour
-005	Boiler Number 5 - 1,096.7 MMBtu/hour
-006	Boiler Number 6 - 3,704.8 MMBtu/hour
-007	Boiler Number 7 - 6,406.4 MMBtu/hour

{Permitting Note: August 28, 2002, Gulf Power Company and the Florida Department of Environmental Protection entered into an agreement titles, "Agreement for the Purpose of Ensuring Compliance with the Ozone Ambient Air Quality Standards". This agreement is the basis for the following permit conditions.}

REQUIREMENTS OF THE AGREEMENT

E.1. Supplemental Conditions. The conditions of this section supplement all other valid air construction and operation permits for these units. These conditions are in addition to all other applicable permit conditions and regulations.
[Rule 62-4.070(3), F.A.C.; and, 0330045-005-AC]

E.2. Plant-Wide NO_X Limit. Emissions of nitrogen oxides (NO_X) from the combined operation of Units -004, -005, -006, and -007 shall not exceed 0.2 lb/MMBtu heat input based on a 30-day rolling average except for periods when Unit -007 is shutdown. The plant-wide daily NO_X emission rate shall be determined by the following equation:

$$\text{Plant-Wide Daily MMBtu-Weighted } NO_X \text{ Emission Rate} = \left[\frac{\sum_{\text{Units 4, 5, 6, 7}} [(\text{Unit \# daily MMBtu}) \times (\text{Unit \# daily } NO_X \text{ CEMS Rate})]}{\sum_{\text{Units 4, 5, 6, 7}} (\text{Unit \# daily MMBtu})} \right]$$

The "Unit # daily MMBtu" shall be determined by the daily as-burned fuel analysis and the fuel fired for each unit. The "Unit # daily NO_X CEMS Rate" shall be determined by the daily average of NO_X CEMS data for each unit and reported in terms of "lb/MMBtu heat input". The plant-wide daily NO_X emissions rate shall be determined each day regardless of the operating status for Unit -007. The plant-wide 30-day rolling NO_X average shall be determined for each 30 sequential Unit -007 operating days, which need not be consecutive. A Unit -007 operating day means any calendar day that Unit -007 operates a minimum of 18 hours. The Unit -007 daily NO_X CEMS rate may consist of less than 18 hours of data if this is due to CEMS malfunction or invalid CEMS data. When the catalyst temperature is below 600° F during a startup or shutdown, NO_X emissions data collected during such periods may be excluded from the daily NO_X average. In accordance with Specific Condition **C.18.**, NO_X emissions data collected during SCR bypass during the non-ozone season may be excluded from the daily NO_X average. The plant-wide NO_X emission standard shall be achieved by utilizing the SCR system for Unit -007 and implementing the selected NO_X control strategy for Units -004, -005, and -006. The effective date for the plant-wide NO_X emission standard is:

a. The startup date of the selected additional NO_X reduction project, (excluding an SCR project for Unit -006), but no later than May 1, 2006; or

b. The startup date of the SCR project for Unit -006, but no later than December 31, 2007.

For purposes of this condition, "startup date" shall mean the date that the permittee demonstrates initial compliance with the terms of the required air construction permit (or other Department approval) that authorized implementation of the additional NO_X reduction project. [Paragraphs 2, 3 and Exhibit B of the Agreement]
[0330045-005-AC]

E.3. NO$_X$ CEMS. To demonstrate compliance with the plant-wide NO_X emissions standard, the permittee shall install, calibrate, operate and maintain continuous emissions monitoring systems (CEMS) to continuously monitor and record the emissions of nitrogen oxides and an appropriate diluent gas (carbon dioxide or oxygen) from Units -004, -005, -006, and -007.
[Exhibit B of the Agreement; and, 0330045-005-AC]

{Permitting Note: The existing NO_X CEMS required by the Acid Rain program satisfy this requirement.}

E.4. Quarterly Report. For each calendar day during the reporting quarter, the permittee shall report the following information related to the NO_X CEMS for Unit -007:

- Daily NO_X emission rate for each boiler, lb/MMBtu;
- Daily heat input rate for each boiler, MMBtu/day;
- 30-day plant-wide NO_X emissions rate, lb/MMBtu;
- Identify whether Unit -007 operated less than 18 hours;
- Identify the occurrence of a Unit -007 startup or shutdown; and
- Identify operation of Unit -007 with SCR bypass for catalyst maintenance or repair and the duration of bypass (hours).

Identify the "F" factor used for any calculations, the method of determination, and type of fuel combusted. For each day that CEMS data was not obtained for at least 18 hours of Unit -007 operation, provide a justification for not obtaining sufficient data and describe the corrective actions taken to prevent this in the future. Identify any emissions data excluded from the calculation of emission rates due to startup, shutdown, or malfunction.
[0330045-005-AC]

{Permitting Notes: To achieve the plant-wide NO_X standard for the Crist Plant, Gulf Power Company will take the following additional actions.

Unit Retirements: The Agreement requires the retirement of Unit -001 within 120 days of receiving a final order from the Public Service Commission that authorizes the recovery of costs associated with the pollution control equipment incurred pursuant to the Agreement though the Environmental Cost Recovery Clause. **(Unit -001 was retired on March 31, 2003.)** A final order is one that is no longer subject to review or appeal by a court of competent jurisdiction. The Agreement also requires the retirement of Units -002 and -003 on or before May 1, 2006.

[Paragraph 4 of the Agreement]

Additional NO_X Reduction Projects: The Agreement requires Gulf Power Company to conduct a variety of engineering studies to determine the feasibility of NO_X reduction technologies for one or more of the three remaining coal-fired units (Units -004, -005, and -006). The studies and related unit-specific demonstration projects may include (but are not limited to) SCR, selective non-catalytic reduction (SNCR) technology, over-fired air (OFA) technology, natural gas re-burn technology, selective use of biomass fuel, etc. The studies must be complete by May 1, 2005. Before implementing any NO_X reduction technology or combination of technologies, Gulf Power Company must obtain written concurrence from the Department that the use thereof is reasonable and necessary to achieve the overall plant-wide NO_X emission standard. If a NO_X reduction technology or a combination of technologies other than an SCR project for Unit 6 is identified as appropriate, Gulf Power Company will implement the technology or combination of technologies on one or more of the three remaining coal-fired units by May 1, 2006. If an SCR project for Unit -006 is identified as the appropriate NO_X reduction technology, Gulf Power Company will implement, begin and continue operating the SCR system by December 31, 2007.

[Paragraph 2 of the Agreement]}

Section IV. Acid Rain Part.

Operated by: Gulf Power Company
ORIS Code: 641

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

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

E.U. ID No.	Brief Description
	(retired March 31, 2003)
-002	Boiler Number 2 - 420 MMBtu/hour **(to be retired by May 1, 2006)**
-003	Boiler Number 3 - 550 MMBtu/hour **(to be retired by May 1, 2006)**
-004	Boiler Number 4 - 1,096.7 MMBtu/hour
-005	Boiler Number 5 - 1,096.7 MMBtu/hour
-006	Boiler Number 6 - 3,704.8 MMBtu/hour
-007	Boiler Number 7 - 6,406.4 MMBtu/hour

A.1. The Phase II permit applications, the Phase II NO_X compliance plans and the Phase II NO_X averaging plans submitted for this facility, as approved by the Department, are a part of this permit (included as Attachments). The owners and operators of these Phase II acid rain units must comply with the standard requirements and special provisions set forth in the applications listed below:

a. DEP Form No. 62-210.900(1)(a), F.A.C., Signed 6/1/04.
b. DEP Form No. 62-210.900(1)(a)4., F.A.C., Signed 6/1/04.
c. DEP Form No. 62-210.900(1)(a)5., F.A.C., Signed 11/18/03.

[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 #	EPA ID	Year	2004	2005	2006	2007	2008
-002	**ID No. 02 2**	**SO_2 allowances, under Table 2 or 3 of 40 CFR 73**	3*	3*	3*	3*	3*
-003	**ID No. 03 3**	**SO_2 allowances, under Table 2 or 3 of 40 CFR 73**	4*	4*	4*	4*	4*

E.U. ID #	EPA ID	Year	2004	2005	2006	2007	2008
-004	**ID No. 04 4**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	2467*	2467*	2467*	2467*	2467*
		NO_X limit	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.52** lb/MMBtu. In addition, this unit shall not have an annual heat input **greater than 5,591,320** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				
-005	**ID No. 05 5**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	2430*	2430*	2430*	2430*	2430*
		NO_X limit	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.60** lb/MMBtu. In addition, this unit shall not have an annual heat input **greater than 5,479,586** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				
-006	**ID No. 06 6**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	8396*	8396*	8396*	8396*	8396*

E.U. ID #	EPA ID	Year	2004	2005	2006	2007	2008
-006 (cont')		**NO_X limit**	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.45** lb/MMBtu. In addition, this unit shall not have an annual heat input **less than 21,086,630** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				
-007	**ID No. 07 7**	**SO_2 allowances, under Table 2, 3, or 4 of 40 CFR 73**	12522*	12522*	12522*	12522*	12522*
		NO_X limit	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves five (5) NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the 2004, 2005, 2006, 2007 and 2008. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.45** lb/MMBtu. In addition, this unit shall not have an annual heat input **less than 34,569,955** MMBtu. Also, see Additional Requirements 1, 2 and 3, below.				

* 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, 3, or 4 of 40 CFR 73.

Additional Requirements

1. Under the plan (NO_X Phase II averaging plan), the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

2. In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only after the Alabama Department of Environmental Management, the Jefferson County (Alabama) Department

of Health, the Georgia Department of Natural Resources and the Mississippi Department of Environmental Quality, have also approved this averaging plan.

3. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

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)1., 2. & 3., 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.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Where an applicable requirement of the Act is more stringent than applicable 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, F.A.C., Definitions – Applicable Requirements.]

A.6. Comments, notes, and justifications: The Designated Representative has changed from Frederick Kuester to G. Edison Holland, Jr. to Robert G. Moore to Bill M. Guthrie to Charles D. McCrary.

The alternative designated representatives have been changed to include Robert G. Moore and James O. Vick.

Reporting Requirements

A.7. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-4, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

A.8. Demonstration of Compliance With the Phase II NO_X Averaging Plan. The Designated Representative shall provide a copy of the demonstration of compliance, prepared in accordance with 40 CFR 76.11(d), to the Department within 60 (sixty) days after the end of the calendar year.
[Rule 62-213.440, F.A.C.]

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

{Permitting note: The U.S. EPA issues Acid Rain Phase I permits.}

The emissions unit(s) listed below are regulated under Acid Rain Part, Phase I

E.U. ID No.	Brief Description
-004	Boiler Number 4 – 1,096.7 MMBtu/hour (Substitution for Unit -007)
-005	Boiler Number 5 – 1,096.7 MMBtu/hour (Substitution for Unit -007)
-006	Boiler Number 6 – 3,704.8 MMBtu/hour
-007	Boiler Number 7 – 6,406.4 MMBtu/hour

B.1. The Phase I permits, issued by the U.S. EPA, are attached to this permit. The owners and operators of these Phase I acid rain units must comply with the standard requirements and special provisions set forth in the Phase I permits issued December 27, 1994.
[Chapter 62-213, F.A.C.]

B.2. Comments, notes, and justifications: None.

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

Gulf Power Company — **DRAFT Permit No.:** 0330045-009-AV
Crist Electric Generating Plant — **Facility ID No.:** 0330045

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

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

	State Registration Number	Contents	Size (Gallons)
1.	1	#2 Diesel – Tractor Fuel	20,000
2.	3	#2 Diesel – Lighter Oil	100,000
3.	4	#2 Diesel – Lighter Oil	100,000
4.	5	#6 Bunker "C"	1,387,000
5.	6	#6 Bunker "C"	1,387,000
6.	7	#6 Bunker "C"	1,387,000
7.	8	Used Oil	15,000
8.	9	Lube Oil	7,000
9.	10	Lube Oil	7,000
10.	11	Waste Oil	12,000
11.	12	Lube Oil	7,000
12.	13	Lube Oil	4,000
13.	14	Lube Oil	4,000
14.	15	Lube Oil	3,000
15.	16	Sulfuric Acid	4,000
16.	17	Sulfuric Acid	6,000
17.	2R1	Gasoline	2,000
18.	--	Used Oil	300

Miscellaneous

19. Fire Safety Equipment
20. Vacuum Pumps
21. Laboratory Equipment
22. Welding Equipment
23. Gulf Power Company Generated Non-hazardous Boiler Chemical Cleaning Wastes (Not to exceed 50 gallons per minute)

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

Gulf Power Company	**DRAFT Permit No.:** 0330045-009-AV
Crist Electric Generating Plant	**Facility ID No.:** 0330045

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

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

E.U. ID No.	**Brief Description of Emissions Units and/or Activity**
-009	Material Handling of Coal and Ash
-010	Fugitive PM Sources – On-site Vehicles
-011	General Purpose Internal Combustion Engines
-012	Cooling Towers (3)
-013	Fugitive PM Sources – Sandblasting Operations

-009 Material Handling of Coal and Ash. Fugitive PM emissions generated from the transfer and handling of coal and ash. SCC: 3-05-101-03.

-010 Fugitive PM Sources. Fugitive PM emissions generated by haul trucks and other on-site vehicles. SCC: 3-05-101-50.

-011 General Purpose Internal Combustion Engines. Located for use at this source are miscellaneous internal combustion engines used to operate the following: welders, compressors, generators, water pumps, sweepers, and other auxiliary equipment.

-012 Cooling Towers. SCC: 3-90-900-04

-013 Fugitive PM Sources. Fugitive PM emissions generated by sandblasting operations. SCC: 3-05-101-99.

Appendix H-1, Permit History/ID Number Changes

(For Tracking Purposes Only)

Gulf Power Company **DRAFT Permit No.**: 0330045-009-AV
Crist Electric Generating Plant **Facility ID No.:** 0330045

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Extended Date [2, 3]	Revised Date(s)
-001	Crist Unit #1	AO17-249656	5/19/94	1/15/96	8/14/96	
-002	Crist Unit #2	AO17-249656	5/19/94	1/15/96	8/14/96	
-003	Crist Unit #3	AO17-249656	5/19/94	1/15/96	8/14/96	
-004	Crist Unit #4	AO17-211303	4/17/92	4/1/97		
		Secretarial ORDER [1]	1/3/86			
		AC17-2126	10/15/75	3/1/77		
-005	Power Boiler No. 5	AO17-211303	4/17/92	4/1/97		
		Secretarial ORDER [1]	10/18/85			
		AC17-2127	10/15/75	3/1/77		
-006	Power Boiler No. 6	AC17-234016	10/7/93	12/1/94		
		AO17-171809	6/6/90	9/2/95	8/14/96	
		Secretarial ORDER [1]	5/12/88			
-007	Crist No. 7	AO17-171806	6/6/90	9/2/95	8/14/96	
		Secretarial ORDER [1]	6/24/88			
-008	Fly Ash Storage Silos (2)	AO17-234356	7/30/93	7/1/98		
		AC17-47675	10/27/81	2/1/83	6/1/83	
All	Initial Title V permit	0330045-001-AV	1/1/00	12/31/04		
-004, -055	Biomass project	0330045-004-AC	12/9/02	10/4/03		
-007	Addition of ESP and SCR	0330045-005-AC	3/3/03	12/1/05		
All	Ambient limit on SO_2	0330045-008-AC	5/18/04	-----		
All	Title V permit Renewal	0330045-009-AV	1/1/05	12/31/09		
All	Revision to SO_2 limit	0330045-010-AC				

1 Secretarial ORDER issued to relax semi-annual PM testing requirement to annual. Previous ORDERs had been issued to relax the Rule required quarterly testing requirement to semi-annual.
2 AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
3 AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., allows Title V Sources to operate under existing valid permits that were in effect at the time of application until the Title V permit becomes effective}

Referenced Attachments

Phase I Acid Rain Permits

Phase II Acid Rain Application/Compliance Plan

Phase II Acid Rain NO_X Compliance Plan

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

Appendix CAM, Compliance Assurance Monitoring Plan

Appendix SO-1, Secretarial ORDER(s)

Appendix SS-1, Stack Sampling Facilities (version dated 10/7/96)

Appendix TV-4, Title V Conditions (version dated 2/12/02)

ASP Number 97-B-01
(With Scrivener's Order Dated July 9, 1997)

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

Table 2-1, Compliance Requirements

Holtom, Jonathan

From: Waters, Glenn D. [GDWATERS@southernco.com]
Sent: Monday, November 01, 2004 5:07 PM
To: Holtom, Jonathan
Subject: FDEP Response to Gulf Latest Crist 7 CAM

We haven't heard back from you yet. Did you receive the following email? Can we finalize all issues with the exception of the permit shield? Dwain

> -----Original Message-----
> From: Waters, Glenn D.
> Sent: Friday, October 29, 2004 8:15 AM
> To: Jonathan Holtom (Jonathan.holtom@dep.state.fl.us); Trina
> Vielhauer (Vielhauer_t@dep.state.fl.us)
> Cc: Vick, James O.
> Subject: Crist 7 CAM Comments
>
> Please see comments in red below per our understanding between Jim and
> Trina. We will have to talk later today about the permit shield issue
> after the attorneys review further. Jim Vick and I will be in a
> meeting between 10-11 EDT and 2:30-5:00 EDT today so I will call or
> email between meetings. Thanks, Dwain
>
> -----Original Message-----
> From: Holtom, Jonathan [mailto:Jonathan.Holtom@dep.state.fl.us]
> Sent: Thursday, October 28, 2004 2:49 PM
> To: Waters, Glenn D.
> Cc: Vielhauer, Trina; Pennington, Jim
> Subject: RE: Latest GP CAM
>
>
> Yes, I was just drafting a note to you about that. EPA has confirmed
> that the permit shield language must stay in the permit because there
> is an open
> notice of violation for the Crist plant.
>
> -Jonathan
>
>
>
> -----Original Message-----
> From: Waters, Glenn D. [mailto:GDWATERS@southernco.com]
> Sent: Thursday, October 28, 2004 3:43 PM
> To: Holtom, Jonathan
> Subject: Re: Latest GP CAM
>
> It will be tomorrow morning before we can respond. We are in a meeting
> this afternoon with executives. I will email or call tomorrow morning
> asap. Any word yet on the permit shield item. Dwain
> --------------------------

> Dwain Waters, QEP
>
>
> -----Original Message-----
> From: Holtom, Jonathan <Jonathan.Holtom@dep.state.fl.us>
> To: Waters, Glenn D. <GDWATERS@southernco.com>
> CC: Vielhauer, Trina <Trina.Vielhauer@dep.state.fl.us>
> Sent: Thu Oct 28 13:56:57 2004
> Subject: Latest GP CAM
>
> Dwain, here is the latest CAM for unit 7 following discussions between
> Trina and Jim Vick. Specific Condition C.23 will be changed as shown
> below to reflect the semi-annual PM testing. Please confirm that this
> is acceptable.
>
>
>
> Thanks for your help, Jonathan.
>
>
>
>
>
>
>
>
>
> TABLE 4. MONITORING APPROACH FOR UNIT -007
>
>
>
>
>
> Compliance Indicator
>
>
> I. Indicator
>
> Opacity of ESP exhaust.
>
>
> Measurement Approach
>
> COMS in ESP outlet duct.
>
>
> II. Indicator Range
>
> An excursion is defined as any 1-hour opacity average greater than
> 15%. Excursions trigger an inspection, any corrective action necessary
> to lower the opacity, and a documentation of the event.
>

> Note: Particulate matter compliance testing shall be conducted on a
> semi-annual basis in order to provide additional assurance that this
> excursion level remains protective of the PM limit. (See Specific
> Condition C.23.b.)
>
>
> III. Performance Criteria
>
>
>
>
>
> A. Data Representativeness
>
> The COMS were installed at representative locations in the ESP exhaust
> per 40 CFR 60, Appendix B, PS-1.
>
>
> B. Verification of Operational Status
>
> Results of initial COMS performance evaluation conducted per PS-1.
>
>
> C. QA/QC Practices and Criteria
>
> The COMS were initially installed and evaluated per PS-1. Zero and
> span drift are checked daily and a quarterly filter audit is
> performed.
>
>
>
> D. Monitoring Frequency
>
> The opacity of the cold-side ESP outlet duct is monitored
> continuously.
>
>
>
>
> E. Data Collection Procedures
>
> The DAS retains all 6-minute average opacity data.
>
>
>
> F. Averaging Period
>
> 6-minute averages. CHANGE F. TO BE CONSISTENT WITH OTHER CAM PLANS
> TO: 6-minute opacity data is used to calculate 1 hour averages.
>
>
>

ok

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

> C.23 Tests Required.
>
> a. Annual Tests Required. Units -006 and -007 shall be tested
> annually for NOX, SO2, PM and ammonia slip emissions in accordance
> with the requirements listed below.
>
> b. Semi-annual Tests required. Unit -007 shall be tested
> semi-annually ~~for 18 months (August 2006)~~ for PM emissions at steady
> state conditions in accordance with the requirements listed below.
> After 18 months the permittee may petition for removal of the
> semi-annual test requirement.
>
> [Rule 62-297.310(7)(a)4., F.A.C.; 0330045-005-AC; and, Applicant
> Request.]

Rem, Note 3

> G. Dwain Waters,QEP
> Air Quality Programs Supervisor
> Gulf Power Company
> One Energy Place
> Pensacola, Florida 32520-0328
> Phone: (850) 444-6527
> Cell: (850) 336-6527
> Pager: (850) 469-4076
> gdwaters@southernco.com

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Department of
Environmental Protection

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

Jeb Bush
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Colleen M. Castille
Secretary

STATEMENT OF BASIS

Progress Energy Florida
DeBary Facility
Volusia County

PROPOSED Title V Air Operation Permit Renewal No. 1270028-007-AV

This PROPOSED 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, 62-212 and 62-213. 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.

This facility consists of ten intermittent duty simple cycle combustion turbine-electrical generators, fuel oil storage tanks and ancillary equipment.

Six of the units pre-date 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines and are not subject to Acid Rain regulations. These six turbines (Units 1 through 6) fire new No. 2 or new No. 6 fuel oil with the sulfur content not to exceed 0.5% and 0.7 % by weight, respectively. Each is a nominal 51.9 MW GE Model MS7000 combustion turbine-electrical generator with a maximum heat input (LHV) of 720 MMBtu/hr (No.6 fuel oil) and 825 MMBtu/hour (No. 2 fuel oil). Emissions are not controlled and each turbine exhausts through a separate stack. The emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These units began commercial service in 1975-1976.

The other four (Units 7 through 10) are subject to Subpart GG and were subject to the Rules for the Prevention of Significant Deterioration (PSD) and a determination of best available control technology (BACT). They are subject to the Acid Rain Phase II requirements of Title IV of the Clean Air Act. These four combustion turbine-electrical generator are fired with natural gas and/or new No. 2 fuel oil and equipped with inlet foggers. Each is a nominal 92.9 MW GE Model PG7111EA with a maximum heat input (LHV) of 1144 MMBtu/hr (No.2 fuel oil) and 1159 MMBtu/hour (natural gas). These units began commercial operation in 1992.

BACT for the four units consists of using clean fuels and good combustion to control particulate emissions (PM/PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2) and volatile organic compounds (VOC). Nitrogen oxides (NO_X) emissions are controlled by water injection to reduce the firing temperature. The BACT and Subpart GG require initial NO_X testing calibration and calibration of the water-to-fuel injection ratio to insure subsequent continuous compliance. Annual compliance tests and calibration are required.

Based on the Title V Air Permit Renewal Application received on May 17, 2004 this facility is a major source of hazardous air pollutants (HAPs). It holds ORIS code 6046 under the federal Acid Rain Program.

The applicant submitted an application for an Air Construction Permit to allow use of existing nitrogen oxides (NO_X) continuous emission monitoring systems (CEMS) at the four newest combustion turbine-electrical generators located at this facility for compliance purposes in lieu of tracking water-to-fuel ratios. A recent revision to Subpart GG allows use of the very accurate CEMS to insure compliance and obviates development of a separate compliance assurance monitoring (CAM) that would otherwise be required pursuant to 40 CFR 64.

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The applicant requested that the CEMS also be used to demonstrate continuous compliance with the permitted BACT NO_X emission limits as revised in various permits issued subsequent to the initial PSD Permit.

The permitted NO_X limits for the four units are 25 parts per million, by volume, corrected to 15 percent oxygen (ppmvd @15% O_2) when firing natural gas and 42 ppmvd @15% O_2 when firing fuel oil. Progress Energy requested that compliance be determined on a 24-hour block (daily) basis and that two hours of excess emissions be allowed for each startup/shutdown cycle.

The Department reviewed hour-by-hour data from the EPA Air Markets Website that contains the CEMS electronic records submitted by companies subject to the Acid Rain regulations. The key findings are:

- The units can be down for months at a time due to their intermittent duty status.
- The units are used most often during the hottest months of the year.
- Most days that the units are used, they operate between two and 12 hours.
- On certain days, the units experienced two startups and shutdowns.
- The data show very consistent compliance with the applicable NO_X emission limits on an hour-by-hour basis. Exceptions are usually related to startups and shutdowns.
- Compliance is consistently demonstrated when a four-hour averaging basis is used. Even fewer exceptions occur and these are usually related to blocks that include startups and shutdowns.

The Department concludes that a four hour averaging basis and the exclusion (if needed) of two hours per day of excess emissions is appropriate when using CEMS in lieu of the water-to-fuel ratio. The Department has determined that allowing more than two hours of excess emissions (such as four hours for two startup/shutdown cycles in a day) would render the process almost meaningless because so many days are characterized by few total hours of operation. **(This matter is under review following receipt of draft comments from applicant. A Department representative will visit the facility prior to issuance of a Proposed Permit to gain first hand understanding of the issue and capabilities of the CEMS equipment, the combustion turbine startup and shutdown characteristics, etc.)**

Information regarding the four GE PG7111EA indicates that startup occurs over a fairly short firing period of roughly 15 minutes. Shutdowns last on the order of five minutes. Presuming that each startup and each shutdown straddle two 15-minute blocks, no more than one hour of data would be excluded from the compliance calculation per startup/shutdown cycle.

Following are the key changes in PROPOSED Title V Air Operation Permit Renewal (1270028-007-AV). They were primarily based on Air Construction Permit 1270028-006-AC that was processed and noticed with the DRAFT Title V Air Operation Permit Renewal.

- The maximum heat input for Units 1, 2, 3, 4, 5, and 6 is adjusted to reflect the capabilities of the equipment at 20 degrees Fahrenheit (^{o}F) instead of $59^{o}F$. There is no practical difference because the allowable heat input rates corresponding to operation at $20^{o}F$ and $59^{o}F$ lie on the same heat input curve. This revision will put the maximum heat input limitations on the same basis as those for the newer units (Units 7, 8, 9 and 10). The affected condition is Condition A.1. Compare with Condition B.1.

- The averaging time for the NO_X emission limits for Units 7, 8, 9, and 10 given in Condition B.7 is set to 4 hours on a rolling basis. Compliance is determined using the Acid Rain CEMS.

- The latest version of 40 CFR 60, Subpart GG – Standards of Performance for Stationary Gas Turbines is incorporated as Condition C.8. This latest version of Subpart GG provides for use of CEMS in lieu of water-to-fuel ratio for compliance with the NOx emissions standard given in Subpart GG and for excess emissions reporting.

- **The permitting note related to heat input was not included for the four units permitted under the rules for the Prevention of Significant Deterioration (Condition B.1) but not for the six units that preexisted the program (Conditions A.1). Information kept on site, data from the EPA Air Markets Website, and Departments standards for equipment and accuracy ensure units continue to operate within their permitted heat input limits. [(Rule 62-297.310(5), F.A.C. incorporated as Specific Condition B.19)]**

- The number of SO2 allowances allocated by EPA was increased from 699 tons per year (TPY) to 705 TPY in accordance with Table 2 – Phase II Allowance Allocations (September 28, 1998, Federal Register/Volume 63, No.187) from 699 TPY to 705 TPY.

- The condition requiring testing at 95 percent of capacity was changed. The new requirement is 90 percent, after which units may operate up to 110 percent of the tested capacity, but not to exceed permitted capacity. The new conditions are in Condition C.3

For the most part, the resulting PROPOSED Title V Air Operation Permit Renewal mirrors the previous version with the exceptions indicated above. The basis for each condition is referenced immediately following each condition.

Holtom, Jonathan

From: Vielhauer, Trina
Sent: Thursday, October 28, 2004 10:06 AM
To: Holtom, Jonathan
Subject: FW: Revised CAM Proposal from Gulf

Let's discuss.

-----Original Message-----
From: Waters, Glenn D. [mailto:GDWATERS@southernco.com]
Sent: Thursday, October 28, 2004 10:03 AM
To: Vielhauer, Trina
Subject: Revised CAM Proposal from Gulf

I believe I can sell the following to the boss. He will be out until 11 am today.
Let me know your thoughts. Dwain

An excursion is defined as any 1-hour opacity average greater than 18% (excluding periods of start-up, shut-down or malfunction). Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. In addition, if an excursion Occurs greater than 3 hours, a steady state particulate matter stack
test shall be performed and Submitted within 30 days. The stack test shall
comply with all of the testing requirements ~~within 30 days~~ and reporting requirements
contained in the preceding specific conditions and, where practicable,
shall be performed while operating at conditions representative of those

?
showing greater than 15% opacity. Units are not required to be brought
on-line solely for the purpose of performing this special compliance test.
If the unit does not operate in the following 30 days, the special compliance
test may be postponed until the unit is brought back on-line. Once back

on-line, the special test shall be performed Within 7 days.

Dwain,
The note that was removed was only a reference to the OPACITY LIMIT of 20% for 6 minutes [it wasn't identifying an exceedance of PM]. Because the 18% on 6 minutes originally proposed was so close to the 20% OPACITY LIMIT from earlier in the permit, the note was there as a reminder that that opacity limit still applied. We've taken that reminder of the 20% opacity limit out.

-----Original Message-----
From: Waters, Glenn D. [mailto:GDWATERS@southernco.com]
Sent: Thursday, October 28, 2004 8:59 AM
To: Vielhauer, Trina
Subject: RE: Crist 6 SNCR Project

I will route to the boss but before we do; There is still a question regarding the exceedance limit? Is the exceedance limit 20% opacity at 3 hours like our other units? I didn't really understand the 20% part below. I don't believe you can just remove it and not address an exceedance under CAM? Can you?

-----Original Message-----
From: Vielhauer, Trina [mailto:Trina.Vielhauer@dep.state.fl.us]
Sent: Wednesday, October 27, 2004 8:02 PM
To: Waters, Glenn D.
Subject: Re: Crist 6 SNCR Project

Dwain,

Following is what we hope to be an acceptable middle-ground on unit 7 CAM. We've gone to the 15 percent on opacity and removed the note about an exceedance of opacity occurs at 20 percent. We have added a requirement to test pm in the event of an hourly opacity over 15 percent. We think it is very unlikely that this will occur. However, if it does, we will have test data to rely upon.

Trina
***
An excursion is defined as any 1-hour opacity average greater than 15% (excluding periods of start-up, shut-down or malfunction). Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. In addition, if an excursion occurs, a steady state particulate matter stack test shall be performed and submitted within 30 days. The stack test shall comply with all of the testing and reporting requirements contained in the preceding specific conditions and, where practicable, shall be performed while operating at conditions representative of those showing greater than 15% opacity. Units are not required to be brought on-line solely for the purpose of performing this special compliance test. If the unit does not operate in the following 30 days, the special compliance test may be postponed until the unit is brought back on-line. Once back on-line, the special test shall be performed within 7 days. Trina Vielhauer

----
Sent from my BlackBerry Wireless Handheld

-----Original Message-----
From: Waters, Glenn D. <GDWATERS@southernco.com>
To: Holtom, Jonathan <Jonathan.Holtom@dep.state.fl.us>
CC: Vielhauer, Trina <Trina.Vielhauer@dep.state.fl.us>; Pennington, Jim <Jim.Pennington@dep.state.fl.us>
Sent: Wed Oct 27 11:08:31 2004
Subject: RE: Crist 6 SNCR Project

Sounds like a plan. We agree. Dwain

-----Original Message-----
From: Holtom, Jonathan [mailto:Jonathan.Holtom@dep.state.fl.us]
Sent: Wednesday, October 27, 2004 9:44 AM
To: Waters, Glenn D.
Cc: Vielhauer, Trina; Pennington, Jim
Subject: Crist 6 SNCR Project

Good Morning Dwain,

After much discussion, we believe that we have found the best solution for your SNCR project. Because the addition of ammonia emissions qualifies as a modification under Rule 62-210.300, an AC permit is required. Since the AC permit that was issued for the SCR on unit 7 is still an active permit (expires 12/1/05), we can open it with a revision to include the SNCR project for unit 6. Doing this will satisfy our rules about the modification and will keep you from having to process a completely new application. It will also be the quickest way for you to receive the authorization to make the desired modifications, because the AC permit will only require a 14 day public comment period. We can then role this project into the Title V permit at the same time that you request a Title V permit revision to incorporate the alternate testing procedure for the ammonia slip on the SNCR on unit 7. Attempting to revise the current Draft Title V permit is not a good idea, because there is not enough processing time left to ensure that you have a new Acid Rain permit by the first of the year.

In order to open the existing AC permit, we will need a written request signed by any Gulf Power Authorized Representative (it doesn't have to be the RO because this is not a Title V action) stating that you would like for us to revise permit number 0330045-005-AC to include SNCR for unit 6. Along with this request, we will need the information listed below (this is the same information that Trina emailed to you last Thursday):

* The designed NOx emission rate to be met after control.

* The designed NOx reduction efficiency (%) at the maximum uncontrolled
NOx emission rate.

* A description of the SNCR system components (tanks, pumps, mixers,
injectors, individual injector levels, control system, monitored parameters, etc.) with a schematic or process flow diagram.

* A description of how the system works to reduce NOx emissions over a
variety of load ranges.

* The furnace temperature operating range.

* The minimum operating temperature before placing the SNCR system in
service.

* Anhydrous or aqueous ammonia?

* The expected operating range for the ammonia injection rate.

* The designed ammonia slip rate.

* A requirement for NOx CEMS monitoring.

* A description of how the control system adjusts the ammonia injection points and rates based on different boiler loads. For example, the SNCR system may consist of three levels of 9 injectors per level. At 70% load, perhaps only levels 1 and 3 are in operation at a given ammonia injection rate to provide the necessary control.

The above information will need to be submitted along with a certification by a Professional Engineer licensed in the state of Florida.

Please call me if you have any questions about this approach.

Jonathan Holtom, P.E.

North Permitting Section, Bureau of Air Regulation

(850) 921-9531

SunCom 291-9531

G. Dwain Waters,QEP
Air Quality Programs Supervisor
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328
Phone: (850) 444-6527
Cell: (850) 336-6527
Pager: (850) 469-4076
gdwaters@southernco.com

Holtom, Jonathan

From: Waters, Glenn D. [GDWATERS@southernco.com]
Sent: Thursday, October 07, 2004 11:26 AM
To: Vielhauer, Trina; Holtom, Jonathan
Subject: Permit Note: Heat Input Compliance

Upon further review, we would like to add to the permit note (B.26 & C.34) for Crist (also: Smith and Scholz), a reference to the recordkeeping provision noting daily records for fuel consumption, i.e. B.33 & C.41 for the Crist permit. Also, in B.33 and C41, please add that daily is a block 24 hour interval and not hourly consumption.

G. Dwain Waters,QEP
Air Quality Programs Supervisor
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328
Phone: (850) 444-6527
Cell: (850) 336-6527
Pager: (850) 469-4076
gdwaters@southernco.com

Subsection B. This section addresses the following emissions units.

Per DL, make sure not to est H.I. be a 24 hr. average

E.U. ID No.	**Brief Description**
-004	Boiler Number 4 (Substitution Phase I Acid Rain Unit)
-005	Boiler Number 5 (Substitution Phase I Acid Rain Unit)

Emissions unit number -004 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 4". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Emissions unit number -005 is a Combustion Engineering tangentially fired, dry bottom boiler designated as "Boiler Number 5". It is rated at a maximum heat input of 1,096.7 million Btu per hour (MMBtu/hour) when firing pulverized coal, natural gas or distillate No. 2 fuel oil (used as back-up fuel). Both units are Phase I Substitution and Phase II Acid Rain Units.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase I and Phase II. These emissions units pre-date PSD regulations and are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Fired Steam Generators with more than 250 million Btu per Hour Heat Input. PM emissions from units -004 and -005 are controlled by hot side (Buell Model # Bal. 2x34n333-4-3p) and cold side (Buell Model # 1.1x48k33-1p) electrostatic precipitators. Unit -004 began commercial operation on July 1, 1959. Unit -005 began commercial operation on June 1, 1961. The generator nameplate rating for unit -004 is 93 MW. The generator nameplate rating for unit -005 is 93 MW. Units -004 and -005 share a common stack with units -002 and -003. Stack height = 450 feet, exit diameter = 18.0 feet, exit temperature = 290 °F, actual volumetric flow rate = 802,500 acfm.}

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
-004	1,096.7	Coal
	1,096.7	Natural Gas
	1,096.7	No. 2 Fuel Oil
	1,096.7	On-Specification Used Oil
-005	1,096.7	Coal
	1,096.7	Natural Gas
	1,096.7	No. 2 Fuel Oil
	1,096.7	On-Specification Used Oil

[Rules 62-4.160(2), 62-204.800, 62-210.200(PTE), 62-214.330 & 62-296.405, F.A.C.; and, permits AC17-2126, AC17-2127 & 0330045-010-AC.]

Recordkeeping and Reporting Requirements

B.33. The owner or operator shall maintain daily records of all fuels consumed.
[Rules 62-213.440 & 62-4.070(3), F.A.C.]

B.34. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

B.35. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

B.36. A maintenance log of the continuous monitoring systems shall be kept showing the following:

a. Time out of service.
b. Calibration and adjustments.

[Rule 62-213.440, F.A.C.; and, AO17-211303, Specific Condition 8.]

B.37. Test Reports.

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

b. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using ASTM D2013-72 and either ASTM D3177-75 or ASTM D4239-85, or the latest edition, to analyze a representative sample of the blended as-fired pulverized coal.
c. Determine and record the density (using ASTM D 1298-80, or equivalent) and the calorific heat value in Btu per pound (using ASTM D 240-76, or the latest edition) of the fuel oil combusted.
d. Determine and record the calorific heat value in Btu per pound of the blended, as-fired pulverized coal using ASTM D2013-72 and either ASTM D2015-77 or D3286-(latest version), or the latest edition.
e. Record daily the amount of each fuel fired, the density of the fuel oil, the heating value of each fuel fired, and the percent sulfur content, by weight, of each fuel fired.
f. Utilize the information in a., b., c., d. and e., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

B.26. Heat Input. Compliance with the heat input limitations specified in Specific Condition **B.1.** shall be demonstrated solely through the use of the composite fuel samples taken by on-site personnel (following the testing requirements contained in Specific Condition **B.25.c. & d.**). Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request.
[0330045-010-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

B.27. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

One Energy Place
Pensacola, Florida 32520

Tel 850.444.6111

RECEIVED
OCT 29 2004
BUREAU OF AIR REGULATION

GULF POWER
A SOUTHERN COMPANY

Certified Mail

October 27, 2004

Mr. Jonathan K. Holtom, P.E.
Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Mail Station #5510
Tallahassee, Florida 32399-2400

Dear Mr.Holtom:

RE: GULF POWER – CRIST,SCHOLZ, LANSING SMITH
DRAFT TITLE V COMMENTS

Attached, please find Gulf Power's signed Responsible Official certification of comments for the Crist, Scholz and Lansing Smith Draft Title V Permits as previously emailed to you on October 19, 2004.

Please let me know if you have any questions regarding our comments.

Sincerely,

Dwain Waters, QEP

G. Dwain Waters, Q.E.P.
Air Quality Programs Supervisor

Cc: Jim Vick, Gulf Power Company
Terry Wright, Gulf Power Company
John Dominey, Gulf Power Company
Michael Burroughs, Gulf Power Company
Marie Largilliere, Gulf Power Company
Kenton Peacock, Gulf Power Company
Angela Morrison, Hopping, Green & Sams

CERTIFICATION BY RESPONSIBLE OFFICIAL
TITLE V COMMENTS

"I, the undersigned, am the responsible official, as defined in Chapter 62-210.200, F.A.C., for the Title V source for which this information is being submitted. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made and data contained in this submission are true, accurate and complete."

Responsible Official Signature:

10/25/04

Gene L. Ussery, Jr.
Vice-President of Power Generation

Date

Crist Draft Title V Comments:
Facility ID No: 0330045
October 15, 2004

Comments:

1) Section I. Facility Information: Subsection A. Facility Description. The description outlines 5 fossil fired steam generators.... The facility has 6; see Statement of Basis.
2) Section I. Facility Information: Section II. Facility-wide Conditions. Item 15. Condition notes reference to Permit Shield in lieu of Condition 52 of Appendix TV-4, Conditions. Gulf Power sees no need for this condition and any reference to on-going litigation in a permit. There are no such litigations on-going with Gulf Power. Please remove condition.
3) Section III. Emissions Units and Conditions. A.21. Heat Input. Please add to A.21 reference to recordkeeping provisions for daily records for fuel consumption, i.e. A. 31. Please note that for A. 31 (Units 2 & 3) natural gas is not currently referenced, only solid and liquid fuel. The condition as written only addresses fuel oil for these units.
4) Section III Emissions Units and Conditions. A.31 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption.
5) Section III Emissions Units and Conditions. B.26. Heat Input. Please add to B.26 reference to recordkeeping provisions for daily records for fuel consumption, i.e. B.33.
6) Section III Emissions Units and Conditions. B.26 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption. Gulf Power will meet greater than 95% daily sampling rate.
7) Section III Emissions Units and Conditions. C.34. Heat Input. Please add to C.34 reference to recordkeeping provisions for daily records for fuel consumption, i.e. C.41.
8) Section III Emissions Units and Conditions. C.41 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption. Gulf Power will meet greater than 95% daily sampling rate.
9) Section IV. Acid Rain Part. Subsection A. E.U. ID. Please add Unit 001 to all references in this section. Gulf Power retains 35 SO2 allowances per year for Unit 001 even after retirement under the Acid Rain Program.
10) Section IV. Acid Rain Part. Subsection A. 6. Please update DR list. Mr. W. Paul Bowers is currently the DR. Delete under alternative designated representative, Mr. Robert G. Moore and substitute Mr. Gene L. Ussery, Jr.
11) Appendix CAM, Compliance Assurance Monitoring Plan. Emissions Unit 007. Please revise the averaging time from 6 minutes to 1 hour for excursion and 6 minutes to 3 hours for exceedance as referenced in the Indicator Range in Table IV. There is no justification for adoption of less than a 3 hour averaging period for monitoring CAM for particulate matter. This unit was CAM tested at 18% opacity at 0.052 lb/mmbtu per EPA CAM protocol.
12) Appendix CAM, Compliance Assurance Monitoring Plan. Emissions Unit 004, 005, 006 & 007. Please clarify that startup, shutdown and other excess emission exemptions do not apply to CAM.

Scholz Draft Title V Comments:
Facility ID No: 0630014
October 15, 2004

Comments:

1. <u>Section III Emissions Units and Conditions. A.25. Heat Input.</u> Please add to A.25 reference to recordkeeping provisions for daily records for fuel consumption, i.e. A.32.
2. <u>Section III Emissions Units and Conditions. A.32 Recordkeeping and Reporting Requirements.</u> Please note that daily means 24 hour block (midnight to midnight) of fuel consumption. Gulf Power will meet greater than 95% daily sampling rate.
3. <u>Section IV. Acid Rain Part. Subsection A. 6.</u> Please update DR list. Mr. W. Paul Bowers is currently the DR. Delete under alternative designated representative, Mr. Robert G. Moore and substitute Mr. Gene L. Ussery, Jr.
4. <u>Appendix CAM, Compliance Assurance Monitoring Plan. Emissions Unit 001 & 002.</u> Please clarify that startup, shutdown and other excess emission exemptions do not apply to CAM.

Lansing Smith Draft Title V Comments:
Facility ID No: 0050014
October 15, 2004

Comments:

1. Statement of Basis. Please note that Lansing Smith Units 4 & 5 do not utilize opacity monitors for compliance as stated in the 6th paragraph.
2. Section III Emissions Units and Conditions. A.25. Heat Input. Please add to A.25 reference to recordkeeping provisions for daily records for fuel consumption, i.e. A.32.
3. Section III Emissions Units and Conditions. A.32 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption. Gulf Power will meet greater than 95% sampling rate.
4. Section III Emissions Units and Conditions. A.39 Ambient Monitoring Requirements. Please remove condition. Gulf Power no longer volunteers to monitor ambient air conditions at this facility.
5. Section III Emissions Units and Conditions. B.18 Periodic Monitoring Requirements. Please revise condition to the latest acceptable language approved by the Department noting VE tests after 400 hours of operation on fuel oil and delete every 150 hours of operation thereafter. Also, delete 20 days of exceeding such operating hours and substitute within the next fiscal year.
6. Section III Emissions Units and Conditions. C.5 Permitted Capacity. (a) Combustion Turbine Capacity. Please correct the description of the unit from HHV to LHV as outlined in the statement of basis and in the general description page (see Subsection C under E.U. 4& 5) of the draft permit.
7. Section III Emissions Units and Conditions. C.15 Excess Emissions, Please add language from the existing Title V permit under C.15 to this permit. "Excess Emissions resulting from startup, shutdown, or malfunction of any emissions unit shall be permitted provided the best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. (Rule 62-620.700(1), F.A.C.). There is no reason to have deleted this condition."
8. Appendix CAM, Compliance Assurance Monitoring Plan. Emissions Unit 001& 002. Please change for Unit 001 the excursion limitation from 30% opacity to 32% as outlined in the application using EPA acceptable CAM protocol. Also, please change the exceedance notation from 34% opacity to 36% as outlined in the application using EPA acceptable protocol. Please clarify that startup, shutdown and other excess emission exemptions do not apply to CAM.
9. Gulf Power has discovered several errors in the tank listing under the Insignificant Emissions List which need to be revised. Please find attached, the corrected Appendix I-1 List of Insignificant Emissions Units and/or Activities for Lansing Smith.

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

Gulf Power Company | **DRAFT Permit No.:** 0050014-010-AV
Lansing Smith Electric Generating Plant | **Facility ID No.:** 0050014

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

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

	State Registration Number	Contents	Size (Gallons)
1.	Tank #1	#2 Diesel - Lighter Oil	25,000
2.	Tank #3	#2 Diesel - CT Fuel Oil	200,000
3.	Tank #4	#2 Diesel - CT Fuel Oil	200,000
4.	Tank #5	#2 Diesel - CT Fuel Oil	200,000
5.	---	Lube Oil	1,000
6.	Tank #7	Used Oil	2,100
7.	---	Lube Oil	581
8.	---	Lube Oil	560
9.	---	Lube Oil	560
10.	---	Lube Oil	560
11.	---	Lube Oil	560
12.	Tank #13	Lube Oil	6,000
13.	Tank #14	Lube Oil	6,000
14.	Tank #15	Lube Oil	6,000
15.	Tank #16	Sulfuric Acid	4,000
16.	--	Maintenance Area, Used Oil	500
17.	--	Maintenance Area, Used Oil	500
18.	--	Tractor Shed Area Used Oil	300
19.	--	Fire Pump Diesel Fuel (2)	500
20.	--	Chlorine (13)	1 ton
21.	--Delete	Used Oil	250
22.	--Delete	Used Oil	500
21	Tank # 18	Diesel Sludge Tank	570
22	---	Gas Condensate Tank U-3	500
23	---	Emergency Generator Diesel	500

Miscellaneous

23. Fire Safety Equipment - Exempted by Rule 62-210.300(3)(a)22., F.A.C.
24. Vacuum Pumps - Exempted by Rule 62-210.300(3)(a)9., F.A.C.
25. Laboratory Equipment - Exempted by Rule 62-210.300(3)(a)15., F.A.C.
26. Welding Equipment - Exempted by Rule 62-210.300(3)(a)16., F.A.C.
27. Gulf Power Company Generated Non-hazardous Boiler Chemical Cleaning Wastes
(Not to exceed 50 gallons per minute)

Jonathan

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

RECEIVED
OCT 29 2004
BUREAU OF AIR REGULATION

In the Matter of an
Application for Permit by:

OGC CASE NO.:
FDEP Draft Permit No.: 0330045-009-AV

Gulf Power Company
Crist Electric Generating Plant
Escambia County, Florida
_______________________________________/

SECOND REQUEST FOR ENLARGEMENT OF TIME

By and through undersigned counsel, Gulf Power Company (Gulf Power) hereby requests, pursuant to Florida Administrative Code Rule 62-110.106(4), an enlargement of time, to and including November 8, 2004, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, Gulf Power states the following:

1. On or about September 29, 2004, Gulf Power Company received from the Department of Environmental Protection ("Department") an "Intent to Issue Title V Air Operation Permit Renewal" and accompanying "Draft Permit," (Draft Permit No. 0330045-009), for the Crist Electric Generating Plant, located on Governors Bayou off 10 Mile Road in Pensacola, Escambia County, Florida.

2. Based on Gulf Power's initial review, the Draft Permit and associated documents contain several provisions that warrant clarification or corrections.

3. October 13, 2004, Gulf Power filed a request for an extension of time to file a petition challenging the Draft Permit so that the parties could have time to discuss potential clarifcations or corrections.

4. By Order dated October 18th, 2004, the Department granted the requested extension until November 1, 2004.

5. Gulf Power and the Department are continuing to discuss potential clarification or corrections that may resolve Gulf Power's concerns about the Draft Permit. However, additional time is needed to complete those discussions.

6. This request is filed simply as a protective measure to avoid waiver of Gulf Power's right to challenge certain conditions contained in the Draft Title V Permit. Grant of this request will not prejudice either party, but will further their mutual interest and hopefully avoid the need to file a Petition and proceed to a formal administrative hearing.

7. Undersigned counsel conferred with Ms. Trina Vielhauer of the Department's Division of Air Resource Management and is authorized to state that the Departmetn does not object to the granting of this request.

WHEREFORE, Gulf Power Company respectfully requests that the time for filing of a Petition for Administrative Proceedings in regard to the Department's Intent to Issue Title V Air Operation Permit No. 0330045-009-AV be formally extended to and including November 8, 2004.

RESPECTFULLY SUBMITTED this 29th day of October, 2004.

By: ______________________________
Gary V. Perko
Fla. Bar No. 0855898
Hopping, Green & Sams, P.A.
123 South Calhoun Street
Post Office Box 6526
Tallahassee, FL 32314
(850) 222-7500
(850) 224-8551 Faxsimile

Attorneys for Gulf Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by Hand Delivery to Kathy Carter, Agency Clerk, and Doug Beason, General Counsel, Florida Department of Environmental Protection, 3900 Commonwealth Boulevard, Suite 300, Tallahassee, Florida 32399-3000; and Trina Vielhauer, Florida Department of Environmental Protection, Division of Air Resource Management, 111 S. Magnolia Drive, Suite 23, Tallahassee, Florida 32399 this 29th day of October, 2004.

Gary V. Perko

116262.1.2

The following items are requested for the Crist Title V Renewal Permit

- For Units 4 & 5, incorporate the use of Sodium Carbonate as outlined in memo to FDEP on September 29, 2003.
- For Units 4 & 5, incorporate biomass as a fuel option as outlined in construction permit in 2002.
- Incorporate the current construction permit for the ESP and SCR on Crist Unit 7.
- Incorporate the final permit revision to change the SO2 emission rate limit for Crist 4-6 for solid fuels from 5.9 lb/mmbtu to 2.4 lb/mmbtu as outlined in the permit (0330045-008-AC) dated June 10, 2004.
- Revise the Crist Acid Rain Permit to include the revised Southern System NOx Averaging Plan.

One Energy Place
Pensacola, Florida 32520

Tel 850.444.6111

GULF POWER
A SOUTHERN COMPANY

June 4, 2004

Certified Mail

Mr. Scott M. Sheplak, P.E.
Department of Environmental Protection
2600 Blair Stone Road
Mail Station #5510
Tallahassee, Florida 32399-2400

Dear Mr. Sheplak:

RE: Acid Rain Permit Application
Crist Electric Generating Plant
Permit No: 0330045-001-AV; ORIS Code No: 641

Attached, please find one original and one copy of the Phase II Acid Rain Permit Application and Phase II NOx Compliance Plan for the Crist Electric Generating Plant (ORIS Code 641). Please note that this request is part of the 5 year renewal process for our acid rain permit and should be included in our Title V renewal process.

If you have any questions or need further information regarding this application under the Acid Rain Program, please call me at (850) 444.6527.

Sincerely,

Dwain Waters, Q.E.P.

G. Dwain Waters, Q.E.P.
Air Quality Programs Supervisor

cc: James O. Vick, Gulf Power Company
Terry Wright, Gulf Power Company
John Dominey, Gulf Power Company
Danny Herrin, Southern Company Services
Douglas Neeley, EPA – Region IV
Sandra Veazey, FDEP – Northwest District

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JUN 08 2004
BUREAU OF AIR REGULATION

Acid Rain Part Application

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

This submission is: ☐ New ☒ Revised

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

Plant Name **CRIST ELECTRIC GENERATING PLANT** State **FL** ORIS Code **641**

STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a." For new units, enter the requested information in columns "c" and "d."

a Unit ID#	b Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	c New Units Commence Operation Date	d New Units Monitor Certification Deadline
002	Yes		
003	Yes		
004	Yes		
005	Yes		
006	Yes		
007	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		

Please Sign Here

CRIST ELECTRIC GENERATING PLANT
Plant Name (from Step 1)

STEP 3
Read the standard requirements

Acid Rain Part Requirements

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

Monitoring Requirements

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

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain part application, the Acid Rain part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

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

Excess Emissions Requirements

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

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the Department:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

CRIST ELECTRIC GENERATING PLANT
Plant Name (from Step 1)

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date

Certification

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

Name **JAMES O. VICK**	
Signature James O Vick	Date 6/1/04

Florida Department of Environmental Protection

Phase II NO_X Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

This submission is: ☐ **New** ☒ **Revised**

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	**Crist Electric Generating Plant** Plant Name	**FL** State	**641** ORIS Code
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and"WB" for wet bottom. Indicate the compliance option selected for each unit.		

	ID# **004** Type **T**	ID# **005** Type **T**	ID# **006** Type **DBW**	ID# **007** Type **DBW**	ID# Type	ID# Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	☐	☐	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☐	☐	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	☒	☒	☒	☒	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐

CRIST ELECTRIC GENERATING PLANT
Plant Name (from Step 1)

STEP 2, cont'd.

	ID#	ID#	ID#	ID#	ID#	ID#
	Type	Type	Type	Type	Type	Type
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)	☐	☐	☐	☐	☐	☐
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign and date.

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Part of its Title V permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

STEP 3, cont'd.

Certification

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

Name **James O. Vick**	
Signature James O Vick	Date 6/1/04

Florida Department of Environmental Protection

Phase II NO_x Averaging Plan

For more information, see instructions for DEP Form No. 62-210.900(1)(a)4.and refer to 40 CFR 76.11

This submission is: [ ] New [X] Revised

STEP 1

Identify the units participating in this averaging plan by plant name, state, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
See Page 3.					

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
0.47	≤	0.47

$$\frac{\sum_{i=1}^{n} (R_{Li} \times HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n} [R_{li} \times HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li}	=	Alternative contemporaneous annual emmision limitation for unit i, in 16/mmBtu, as specified in column (b) of Step 1;
R_{li}	=	Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;
HI_i	=	Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;
n	=	Number of units in the averaging plan

Southern Company Averaging Plan Participating Plants

STEP 3

Mark one of the two options and enter dates.

☐ This plan is effective for calendar year ____________ through calendar year ____________ *unless notification to terminate the plan is given.*

[X] Treat this plan as [5] identical plans, each effective for one calendar year for the following calendar years: 2004, 2005, 2006, 2007 and 2008 unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_x under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and

(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,

(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or

(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.

(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

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

Name W. Paul Bowers	
Signature W. Paul Bowers	Date 18 NOV 03'

Southern Company Averaging Plan Participating Plants
Plant Name (from Step 1) as Listed in Step 1.

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Barry	AL	1	0.40	0.57	9,899,353
Barry	AL	2	0.40	0.57	8,827,877
Barry	AL	3	0.40	0.57	16,115,170
Barry	AL	4	0.40	0.45	26,192,590
Barry	AL	5	0.40	0.45	51,553,955
Bowen	GA	1	0.45	0.42	45,308,998
Bowen	GA	2	0.45	0.43	44,124,507
Bowen	GA	3	0.45	0.43	59,801,873
Bowen	GA	4	0.45	0.43	60,182,168
Branch	GA	1	0.68	0.99	13,188,369
Branch	GA	2	0.50	0.72	18,342,165
Branch	GA	3	0.68	0.84	26,905,201
Branch	GA	4	0.68	0.84	30,127,590
Crist	FL	4	0.45	0.52	5,591,320
Crist	FL	5	0.45	0.60	5,479,586
Crist	FL	6	0.50	0.45	21,086,630
Crist	FL	7	0.50	0.45	34,569,955
Daniel	MS	1	0.45	0.33	30,626,415
Daniel	MS	2	0.45	0.33	40,588,498
Gadsden	AL	1	0.45	0.70	2,711,382
Gadsden	AL	2	0.45	0.70	3,120,871
Gaston	AL	1	0.50	0.52	18,858,472
Gaston	AL	2	0.50	0.52	16,624,702
Gaston	AL	3	0.50	0.52	18,430,084
Gaston	AL	4	0.50	0.52	18,740,418
Gaston	AL	5	0.45	0.48	47,511,274
Gorgas	AL	6	0.46	0.55	4,410,470
Gorgas	AL	7	0.46	0.55	4,567,585
Gorgas	AL	8	0.40	0.50	9,965,627
Gorgas	AL	9	0.40	0.50	9,120,885
Gorgas	AL	10	0.40	0.35	45,358,619

Southern Company Averaging Plan Participating Plants
as Listed in Step 1.
Plant Name (from Step 1)

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Greene Co	AL	1	0.68	0.82	17,363,013
Greene Co	AL	2	0.46	0.50	19,145,604
Hammond	GA	1	0.50	0.83	6,007,234
Hammond	GA	2	0.50	0.83	5,605,352
Hammond	GA	3	0.50	0.83	6,386,989
Hammond	GA	4	0.50	0.45	26,721,145
Kraft	GA	1	0.45	0.58	3,578,077
Kraft	GA	2	0.45	0.58	3,745,253
Kraft	GA	3	0.45	0.58	7,231,649
L. Smith	FL	1	0.40	0.62	11,275,531
L. Smith	FL	2	0.40	0.44	9,250,882
McDonough	GA	1	0.45	0.42	18,180,480
McDonough	GA	2	0.45	0.42	17,346,682
McIntosh	GA	1	0.50	0.86	11,087,042
Miller	AL	1	0.46	0.37	47,413,738
Miller	AL	2	0.46	0.37	52,747,691
Miller	AL	3	0.46	0.28	44,422,395
Miller	AL	4	0.46	0.28	47,115,364
Mitchell	GA	3	0.45	0.62	6,652,246
Scherer	GA	1	0.40	0.50	52,573,864
Scherer	GA	2	0.40	0.50	55,563,600
Scherer	GA	3	0.45	0.29	53,365,333
Scherer	GA	4	0.40	0.30	70,093,731
Scholz	FL	1	0.50	0.68	2,365,039
Scholz	FL	2	0.50	0.77	2,429,511
Wansley	GA	1	0.45	0.41	53,141,279
Wansley	GA	2	0.45	0.42	49,741,786
Watson	MS	4	0.50	0.50	16,243,776
Watson	MS	5	0.50	0.65	35,347,433
Yates	GA	1	0.45	0.48	4,977,822
Yates	GA	2	0.45	0.48	4,976,029
Yates	GA	3	0.45	0.48	4,080,042
Yates	GA	4	0.45	0.40	6,554,969
Yates	GA	5	0.45	0.40	6,415,254
Yates	GA	6	0.45	0.33	19,199,860
Yates	GA	7	0.45	0.30	15,577,083

Acid Rain Part Application

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

This submission is: ☐ New ☒ Revised

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

Plant Name **CRIST ELECTRIC GENERATING PLANT** State **FL** ORIS Code **641**

STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a." For new units, enter the requested information in columns "c" and "d."

a Unit ID#	b Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	c New Units Commence Operation Date	d New Units Monitor Certification Deadline
002	Yes		
003	Yes		
004	Yes		
005	Yes		
006	Yes		
007	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		

CRIST ELECTRIC GENERATING PLANT
Plant Name (from Step 1)

STEP 3
Read the standard requirements

Acid Rain Part Requirements

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

Monitoring Requirements

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

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain part application, the Acid Rain part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

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

Excess Emissions Requirements

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

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the Department:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

CRIST ELECTRIC GENERATING PLANT
Plant Name (from Step 1)

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_X averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date

Certification

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

Name **JAMES O. VICK**	
Signature James O Vick	Date 6/1/04

Florida Department of Environmental Protection

Phase II NO_X Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

This submission is: ☐ **New** ☒ **Revised**

Page _1_ of _1_

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	**Crist Electric Generating Plant** Plant Name	**FL** State	**641** ORIS Code
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and"WB" for wet bottom. Indicate the compliance option selected for each unit.		

	ID# **004**	ID# **005**	ID# **006**	ID# **007**	ID#	ID#
	Type **T**	Type **T**	Type **DBW**	Type **DBW**	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	☐	☐	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☐	☐	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	☒	☒	☒	☒	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐

CRIST ELECTRIC GENERATING PLANT
Plant Name (from Step 1)

STEP 2, cont'd.

	ID#	ID#	ID#	ID#	ID#	ID#
	Type	Type	Type	Type	Type	Type
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)	☐	☐	☐	☐	☐	☐
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign and date.

Standard Requirements
General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Part of its Title V permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

STEP 3, cont'd.

Certification

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

Name James O. Vick	
Signature James O Vick	Date 6/1/04

Florida Department of Environmental Protection

Phase II NO_x Averaging Plan

For more information, see instructions for DEP Form No. 62-210.900(1)(a)4.and refer to 40 CFR 76.11

This submission is: ☐ New ☒ Revised

STEP 1

Identify the units participating in this averaging plan by plant name, state, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
See Page 3.					

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
0.47	≤	0.47

$$\frac{\sum_{i=1}^{n} (R_{Li} \times HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n} [R_{li} \times HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emmision limitation for unit i, in 16/mmBtu, as specified in column (b) of Step 1;

R_{li} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

Southern Company Averaging Plan Participating Plants

STEP 3

Mark one of the two options and enter dates.

☐ This plan is effective for calendar year ____________ **through calendar year** ______________ unless notification to terminate the plan **is given.**

[x] Treat this plan as [5] identical plans, each effective for one **calendar year for the following** calendar years: 2004, 2005, 2006, 2007 and 2008 unless notification **to terminate** one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance **with the Acid Rain** emission limitation for NO_x under the plan only if the following requirements **are met:**

(i) For each unit, the unit's actual annual average emission **rate for the calendar year, in** lb/mmBtu, is less than or equal to its alternative contemporaneous **annual emission** limitation in the averaging plan, and

(a) For each unit with an alternative contemporaneous **emission limitation less stringent** than the applicable emission limitation in 40 CFR **76.5, 76.6, or 76.7, the actual annual** heat input for the calendar year does not exceed **the annual heat input limit in the** averaging **plan,**

(b) For each unit with an alternative contemporaneous **emission limitation more** stringent than the applicable emission limitation **in 40 CFR 76.5, 76.6, or 76.7, the** actual annual heat input for the calendar year **is not less than the annual heat input limit** in the averaging **plan, or**

(ii) If one or more of the units does not meet the requirements **of (i), the designated** representative shall demonstrate, in accordance with **40 CFR 76.11(d)(1)(ii)(A) and (B),** that the actual Btu-weighted annual average emission **rate for the units in the plan is less** than or equal to the Btu-weighted annual average rate **for the same units had they each** been operated, during the same period of time, **in compliance with the applicable emission** limitations in 40 CFR 76.5, 76.6, or 76.7.

(iii) If there is a successful group showing of compliance **under 40 CFR 76.11(d)(1)(ii)(A)** and (B) for a calendar year, then all units in the averaging **plan shall be deemed to be in** compliance for that year with their alternative contemporaneous **emission limitations and** annual heat input **limits under (i).**

Liability

The owners and operators of a unit governed by an approved **averaging plan shall be liable for** any violation of the plan or this section at that unit or any other **unit in the plan, including liability** for fulfilling the obligations specified in part 77 of this chapter **and sections 113 and 411 of the Act.**

Termination

The designated representative may submit a notification **to terminate an approved averaging** plan, in accordance with 40 CFR 72.40(d), **no later than October 1 of the calendar year for which the plan is to be terminated.**

Certification

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

Name	W. Paul Bowers		
Signature	W. Paul Bowers	Date	18 NOV 03

DEP Form No. 62-210.900(1)(a)5. - Form
Effective: 1/6/98

Southern Company Averaging Plan Participating Plants

Plant Name (from Step 1) as Listed in Step 1.

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Barry	AL	1	0.40	0.57	9,899,353
Barry	AL	2	0.40	0.57	8,827,877
Barry	AL	3	0.40	0.57	16,115,170
Barry	AL	4	0.40	0.45	26,192,590
Barry	AL	5	0.40	0.45	51,553,955
Bowen	GA	1	0.45	0.42	45,308,998
Bowen	GA	2	0.45	0.43	44,124,507
Bowen	GA	3	0.45	0.43	59,801,873
Bowen	GA	4	0.45	0.43	60,182,168
Branch	GA	1	0.68	0.99	13,188,369
Branch	GA	2	0.50	0.72	18,342,165
Branch	GA	3	0.68	0.84	26,905,201
Branch	GA	4	0.68	0.84	30,127,590
Crist	FL	4	0.45	0.52	5,591,320
Crist	FL	5	0.45	0.60	5,479,586
Crist	FL	6	0.50	0.45	21,086,630
Crist	FL	7	0.50	0.45	34,569,955
Daniel	MS	1	0.45	0.33	30,626,415
Daniel	MS	2	0.45	0.33	40,588,498
Gadsden	AL	1	0.45	0.70	2,711,382
Gadsden	AL	2	0.45	0.70	3,120,871
Gaston	AL	1	0.50	0.52	18,858,472
Gaston	AL	2	0.50	0.52	16,624,702
Gaston	AL	3	0.50	0.52	18,430,084
Gaston	AL	4	0.50	0.52	18,740,418
Gaston	AL	5	0.45	0.48	47,511,274
Gorgas	AL	6	0.46	0.55	4,410,470
Gorgas	AL	7	0.46	0.55	4,567,585
Gorgas	AL	8	0.40	0.50	9,965,627
Gorgas	AL	9	0.40	0.50	9,120,885
Gorgas	AL	10	0.40	0.35	45,358,619

Southern Company Averaging Plan Participating Plants as Listed in Step 1.
Plant Name (from Step 1)

NO_x Averaging - Page 4

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Greene Co	AL	1	0.68	0.82	17,363,013
Greene Co	AL	2	0.46	0.50	19,145,604
Hammond	GA	1	0.50	0.83	6,007,234
Hammond	GA	2	0.50	0.83	5,605,352
Hammond	GA	3	0.50	0.83	6,386,989
Hammond	GA	4	0.50	0.45	26,721,145
Kraft	GA	1	0.45	0.58	3,578,077
Kraft	GA	2	0.45	0.58	3,745,253
Kraft	GA	3	0.45	0.58	7,231,649
L. Smith	FL	1	0.40	0.62	11,275,531
L. Smith	FL	2	0.40	0.44	9,250,882
McDonough	GA	1	0.45	0.42	18,180,480
McDonough	GA	2	0.45	0.42	17,346,682
McIntosh	GA	1	0.50	0.86	11,087,042
Miller	AL	1	0.46	0.37	47,413,738
Miller	AL	2	0.46	0.37	52,747,691
Miller	AL	3	0.46	0.28	44,422,395
Miller	AL	4	0.46	0.28	47,115,364
Mitchell	GA	3	0.45	0.62	6,652,246
Scherer	GA	1	0.40	0.50	52,573,864
Scherer	GA	2	0.40	0.50	55,563,600
Scherer	GA	3	0.45	0.29	53,365,333
Scherer	GA	4	0.40	0.30	70,093,731
Scholz	FL	1	0.50	0.68	2,365,039
Scholz	FL	2	0.50	0.77	2,429,511
Wansley	GA	1	0.45	0.41	53,141,279
Wansley	GA	2	0.45	0.42	49,741,786
Watson	MS	4	0.50	0.50	16,243,776
Watson	MS	5	0.50	0.65	35,347,433
Yates	GA	1	0.45	0.48	4,977,822
Yates	GA	2	0.45	0.48	4,976,029
Yates	GA	3	0.45	0.48	4,080,042
Yates	GA	4	0.45	0.40	6,554,969
Yates	GA	5	0.45	0.40	6,415,254
Yates	GA	6	0.45	0.33	19,199,860
Yates	GA	7	0.45	0.30	15,577,083

One Energy Place
Pensacola, Florida 32520

Tel 850.444.6111

RECEIVED
JUL 14 2004
BUREAU OF AIR REGULATION

GULF POWER
A SOUTHERN COMPANY

July 09, 2004

CERTIFIED MAIL

Ms. Sandra Veazey
Florida Department of Environmental Protection
Northwest District
160 Governmental Center
Pensacola, Florida 32501-5794

Ms. Veazey:

Crist Electric Generating Plant – CONSTRUCTION PERMIT NO.: 0330045-007-AC
Re: Unit 7 CAM TEST

Please find attached one copy of the CAM Test Reports for Plant Crist Unit 7 as required under the Construction permit issued on April 22, 2004.

The testing was conducted to gather data for the development of a CAM protocol for this Unit. Testing was conducted by Sanders Engineering and Analytical Services, Inc. with the guidance of Southern Company Services and supervised by Greg Terry, P.E., Gulf Power Co. and Kevin Beaty, Environmental Affairs Specialist, Gulf Power Co.

If you have any questions regarding the Crist Unit 7 test reports or the development of the CAM protocol for this unit, please call Kevin Beaty at (850) 444-6091.

Sincerely,

Dwain Waters, QEP

G. Dwain Waters, QEP
Air Quality Programs Supervisor

Enclosure:
Attachments:

cc:	J. W. Martin	J. M. Dominey	file
	A. S. Nelson	J. O. Vick	
	J. M. McPherson	Al L. Linero, FDEP-BAR	

CERTIFICATION BY RESPONSIBLE OFFICIAL

"I, the undersigned, am the responsible official, as defined in Chapter 62-210.200, F.A.C., for Gulf Power Title V sources for which this report is being submitted. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made and data contained in this report are true, accurate and complete."

Responsible Official Signature:

Gene L. Ussery Jr. 7-13-04

Gene L. Ussery Jr.
Vice-President of Power Generation

Date:

SANDERS ENGINEERING & ANALYTICAL SERVICES, INC.

PARTICULATE EMISSIONS TEST REPORT
SOOT BLOWING OPERATIONS
CAM BASELINE

FOR

GULF POWER COMPANY
Plant Crist, Unit 7
Pensacola, Florida

RECEIVED
JUL 14 2004
BUREAU OF AIR REGULATION

SEAS

June 14, 2004

1568 LEROY STEVENS ROAD
MOBILE, ALABAMA 36695
(251) 633-4120
FAX: (251) 633-2285
E-MAIL: sanders@sandersengineering.com

REPORT CERTIFICATION

I have reviewed the "Particulate Emissions Test Report – Soot Blowing Operations" for the testing performed for Gulf Power Company on Unit 7 located at the Plant Crist facility in Pensacola, Florida. I hereby certify that it is authentic and accurate to the best of my knowledge.

Date: 6/29/04

Signature:

Johnny W. Sanders, P.E. M.P.H.
President

TABLE OF CONTENTS

LIST OF TABLES

ILLUSTRATIONS

1. INTRODUCTION

Sanders Engineering & Analytical Services, Inc. (SEAS) performed particulate emissions testing during soot blowing operations for Gulf Power Company on Unit 7 located at the Plant Crist facility in Pensacola, Florida (Permit No. 1OPEN17004507). The testing was conducted June 14, 2004. The testing was performed in accordance with the applicable U.S. EPA procedures specified at **40 CFR, Part 60, Appendix A**, **Methods 1, 2, 3a, 4, and 17**. Further discussions of the test methods are included later in the report.

The purpose of the testing was to demonstrate compliance with the rules and regulations of the U. S. Environmental Protection Agency, and to meet the necessary requirements contained in the permit to operate issued by the Florida Department of Environmental Protection. The tests were conducted by Mr. John Rampulla, Mr. John Wilson, and Mr. Eric Jones of Sanders Engineering & Analytical Services, Inc., and were coordinated with Mr. Kevin Beaty of Gulf Power Company. The Florida Department of Environmental Protection was notified so a representative could be present to observe the testing.

The results of the testing prove the unit to be in compliance with the particulate emission limitations contained in the permit while operating under soot blowing conditions issued by the Florida Department of Environmental Protection.

2. DESCRIPTION OF SAMPLING PROGRAM

The sampling program consisted of particulate emissions testing in compliance with US EPA methods. The following is a brief description of this type of testing. The particulate sample was extracted from the stack isokinetically through a stainless steel nozzle and probe onto a pre-weighed glass fiber filter. The sample was taken at a series of points across the stack. Each point represented an equal area of stack. The isokinetic sampling rate and volumetric flow rate was monitored by an S-type pitot tube attached to the probe. Calibrations of the particulate testing equipment including pitots, thermocouples, magnehelics, and other measurement devices are included in Appendix A. A detailed description of the testing procedures and schematic of the sampling train is presented in Section 6. The field data sheets for this testing are presented in Appendix B. Sample calculations of Run 1 are presented in Appendix C. The precipitator data as supplied by Gulf Power Company is presented in Appendix D.

3. SUMMARY AND DISCUSSION OF RESULTS

There were no unusual problems encountered during the performance of the testing. During the performance of the soot blowing testing the average heat input, as based on F-factor calculations, was 4924 million Btu per hour. The results of the testing show the particulate emission rate for the unit during soot blowing operations is 0.0080 pounds per million Btu compared to an allowable limit contained in the permit of 0.3 pounds per million Btu. The results of the particulate emissions testing for each of the runs are summarized in Table I. A graphical representation of the results for each of the runs is presented in Figure 1.

The results of the testing prove the unit to be in compliance with the particulate emission limitations contained in the permit while operating under soot blowing conditions issued by the Florida Department of Environmental Protection.

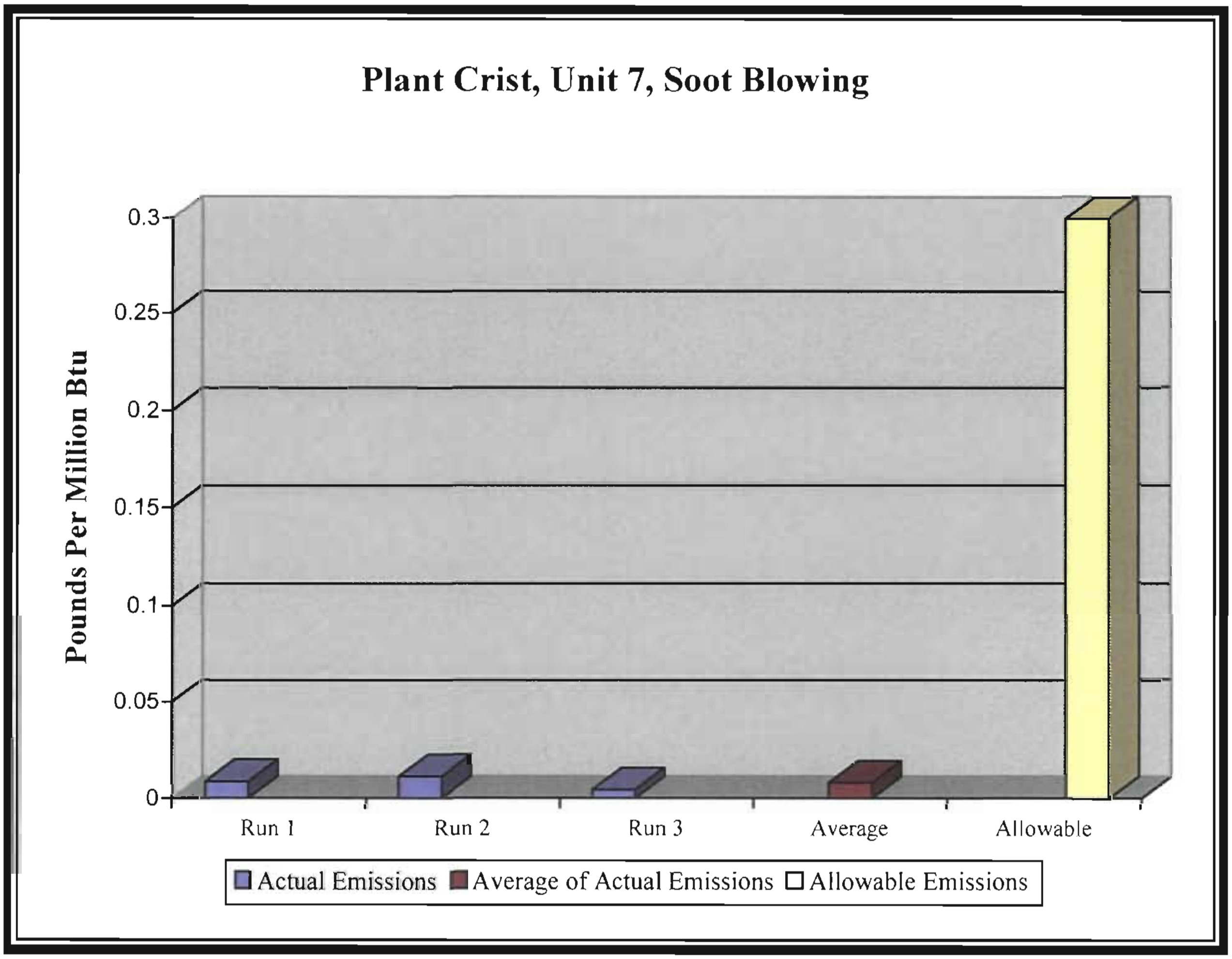
TABLE I. SUMMARY OF PARTICULATE EMISSIONS TEST RESULTS
GULF POWER COMPANY
PLANT CRIST, UNIT 7
SOOT BLOWING OPERATIONS

Title of Run		RUN 1	RUN 2	RUN 3
Date	Month/Day/Year	6/14/2004	6/14/2004	6/14/2004
Sampling Time -Start	Military	0805	0945	1112
Sampling Time -Stop	Military	0913	1050	1218
Stack Static Pressure	Inches Water	2.00	2.00	2.00
Barometric Pressure	Inches Mercury	29.98	29.98	29.98
Meter Correction Factor	dimensionless	1.011	1.011	1.011
Oxygen Concentration	Mole Percent O2	6.0	5.8	5.5
Carbon Dioxide Concentration	Mole Percent CO2	12.0	12.0	12.0
Volume of Gas Metered	Actual Cubic Feet	36.750	36.525	37.200
Volume of Water Collected	Milliliters	75.0	75.0	85.0
Sampling Time	Minutes	60	60	60
Nozzle Diameter	Inches	0.190	0.190	0.190
Weight of Solids Collected	Milligrams	10.3	13.6	5.5
Area of Stack	Square Feet	366.2625	366.2625	366.2625
Avg. Sqr. Root Velocity Pressure	Inches Water	1.2155	1.2188	1.2071
Average Orifice Pressure (ΔH)	Inches Water	1.3	1.4	1.7
Average Stack Temperature	Degrees F	333.2	334.3	338.8
Average Meter Temperature	Degrees F	84.0	80.3	81.2

Calculations

		RUN 1	RUN 2	RUN 3	*3 Runs* Average
Volume of Gas Sampled	Standard Dry Cubic Feet	36.261	36.289	36.927	36.492
Molecular Wt. of Stack Gas	LB/LB-MOLE	29.081	29.075	28.953	29.036
Water vapor in Stack Gas	Percent	8.9	8.9	9.8	9.2
Average Stack Gas Velocity	Feet per second	83.04	83.33	82.94	83.10
Stack Gas Flow Rate	Actual Cubic Feet Per Minute	1,824,841	1,831,280	1,822,637	1,826,253
Stack Gas Flow Rate	Standard Wet Cubic Feet Per Minute	1,222,871	1,225,434	1,212,828	1,220,378
Stack Gas Flow Rate	Standard Dry Cubic Feet Per Minute	1,114,378	1,116,792	1,094,266	1,108,478
Particulate Concentration	Grains per Standard Dry Cubic Foot	0.00437	0.00577	0.00229	0.00415
Particulate Concentration	Grains per Actual Cubic Foot	0.00267	0.00352	0.00138	0.00252
Particulate Emission Rate	Pounds per Hour	41.78	55.25	21.51	39.51
Particulate Emission Rate	Pounds per Million Btu (O2 F Factor)	**0.0086**	**0.0112**	**0.0043**	**0.0080**
Allowable Particulate Emission Rate		***0.3***	***0.3***	***0.3***	***0.3***
Heat Input (O2 F Factor)	Million Btu per Hour	4,874	4,950	4,947	4,924
Isokinetic Rate	Percent	100.9	100.7	104.6	102.1

FIGURE 1. GRAPHICAL REPRESENTATION OF PARTICULATE EMISSIONS TEST RESULTS



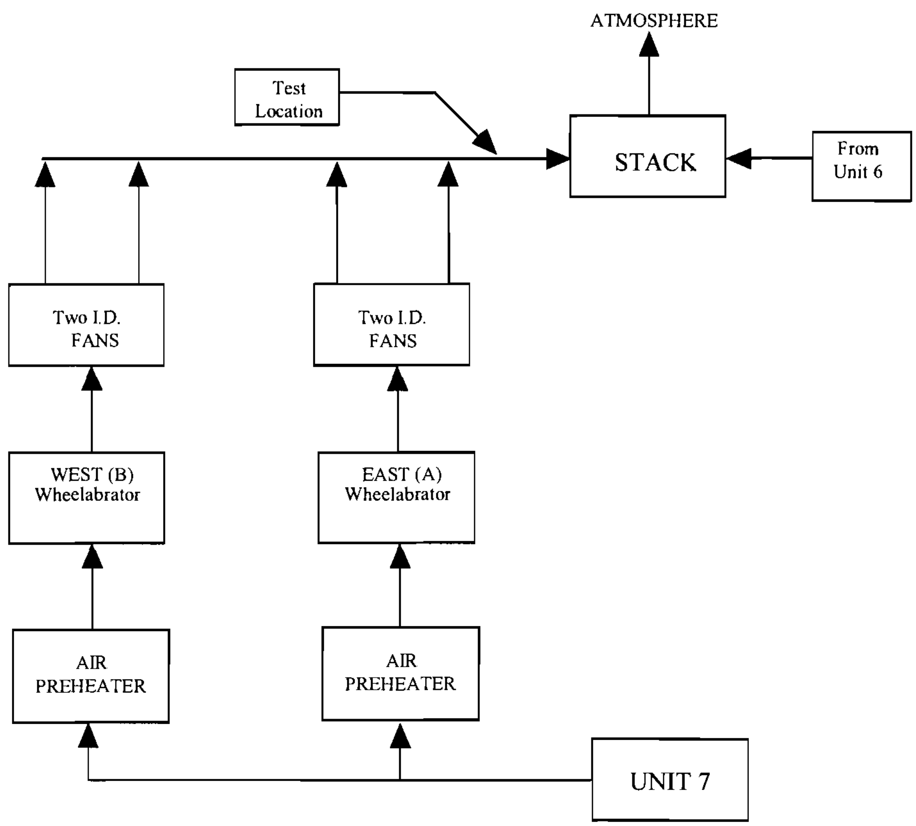
4. PROCESS DESCRIPTION

The process consists of a steam electric generating unit firing bituminous coal for the production of electric energy. The coal is received by barge, and loaded directly onto the conveyor feeding the plant or onto the stockpile and later loaded onto the conveyor belt transporting the coal to the plant. The coal from the conveyor is loaded into bunkers capable of holding between 36 to 48 hours supply of coal. The coal is then fed to pulverizing mills before being fired in the unit through the burners. Upon combustion of the coal in the fire box, approximately 20 percent of the ash falls to the bottom of the boiler and is removed by the ash removal system. The remaining 80 percent exits with the flue gases through the heat exchange and economizer sections of the furnace, and is collected by electrostatic precipitators.

4.1. Source Air Flow

As shown in Figure 2, the flue gases exit the boiler and are separated into ducts A and B before entering air preheaters. They are then routed to a cold side electrostatic precipitator. The flue gases exiting the cold side electrostatic precipitator are exhausted through a stack into the atmosphere.

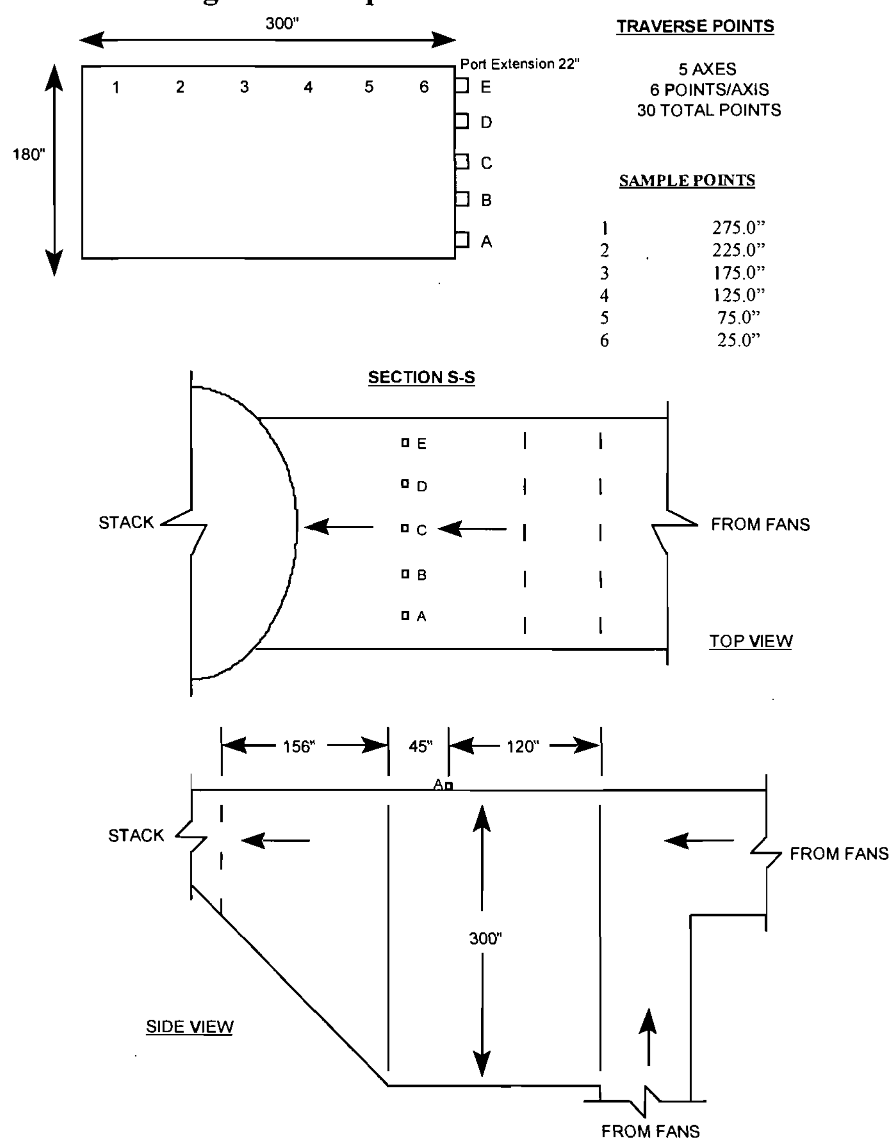
Figure 2. Air Flow Schematic



5. SAMPLE POINT LOCATION

The sample point locations and outlet duct schematic are presented in Figure 3. Method 1 was used for determination of the number and location of sampling points. The minimum number of points (25) required for rectangular stacks was met by sampling a total of 30 points. A new stack area of 366.2625 is used in all calculations. The new area is derived from the unit 7 default wall affect factor.

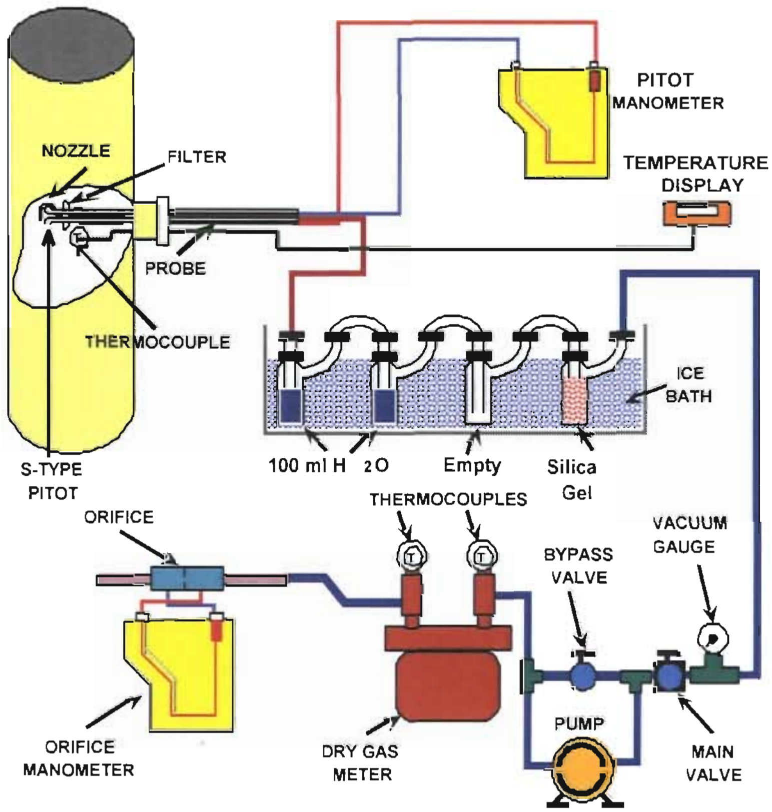
Figure 3. Sample Point Locations



6. PARTICULATE SAMPLING PROCEDURE (EPA Method 17)

The sampling procedure utilized is that specified in **40 CFR, Part 60, Appendix A, Method 17**. A brief description of this procedure is as follows:

Figure 4. Particulate Sampling Train (Method 17)



The first impingers are partially filled with 100 milliliters of deionized water. The next impinger is left empty to act as a moisture trap. Preweighed 6 to 16 mesh indication silica gel is added to the last impinger. The sampling equipment manufactured by Lear Siegler (Model 100) or Sanders Engineering (Model 200) is assembled as shown in the attached drawing. The system is leak checked by plugging the inlet to the nozzle and pulling a 15-inch mercury vacuum. A leakage rate not in excess of 0.02 cubic feet per minute is considered acceptable.

The inside dimensions of the stack liner are measured and recorded. The required number of sampling points is marked on the probe for easy visibility. The range of velocity pressure, the percent moisture, and the temperature of the effluent gases are determined. From this data, the correct nozzle size and the nomograph multiplication factor are determined.

Crushed ice is placed around the impingers. The nozzle is placed on the first traverse point with the tip pointing directly into the gas stream. The pump is started immediately and the flow adjusted to isokinetic sampling conditions. After the required time interval has elapsed, the probe is repositioned to the next traverse point and isokinetic sampling is re-established. This is performed for each point until the run is completed. Readings are taken at each point and recorded on the field data sheet. At the conclusion of each run, the pump is turned off, final readings are recorded, and final system leak checks are performed.

6.1. Particulate Sample Recovery

Care is exercised in moving the collection train to the sample recovery area to minimize the loss of collected sample, or the gain of extraneous particulate matter. The volume of water in the impingers is measured, and the silica gel impinger weighed and recorded on the field data sheet. The nozzle and all sample-exposed surfaces are washed with reagent grade acetone into a clean sample container. A brush is used to loosen any adhering particulate matter and subsequent washings are placed into the container. The filter is carefully removed from the fritted support and placed in a clean separate sample container. A sample of the acetone used in the washing is saved for a blank laboratory analysis.

6.2. Particulate Analytical Procedures

The filter and any loose particulate matter are transferred from the sample container to a clean, tared weighing dish. The filter is placed in a desiccator for at least 24 hours and then weighed to the nearest 0.1 milligram until a constant weight is obtained. The original weight of the filter is deducted and the weight gain recorded to the nearest 0.1 milligram.

The wash solution is transferred to a clean, tared beaker. The solution is evaporated to dryness, desiccated to a constant weight, and the weight gain is recorded to the nearest 0.1 milligram.

7. QUALITY ASSURANCE

In order to ensure the accuracy of all the data collected in the field and at the laboratory, SEAS has instituted a comprehensive quality assurance and quality control program. New or repaired items which require calibration are calibrated before their initial use in the field. Equipment whose calibration may change with use are calibrated before and after each use. When an item is found to be out of calibration the unit is either discarded or repaired and recalibrated before being returned to service. All equipment is periodically recalibrated in full regardless of the results of the regular inspections or its present calibration status. Calibrations are performed in a manner consistent with the EPA reference methods recommended in the "Quality Assurance Handbook for Air Pollution Measurement Systems" published by the US Environmental Protection Agency. To the maximum degree possible all calibrations are traceable to the National Institute of Standards & Technology (NIST).

In order to ensure that the testing will be performed in a timely manner without undue delays, SEAS sampling vans are equipped with duplicate sampling devices for almost every device needed to perform the test. If a particular device is broken or does not pass inspection a second device is available immediately at the site for use. Any device which appears to be outside calibration, or is in need of repair, is tagged in the field and repaired, calibrated, or discarded immediately upon return to the laboratory.

7.1. *Calibrations*

Certain pieces of equipment need to be calibrated before and after each test. Those items include pitot tubes, differential pressure gauges, dry gas meter, and nozzles used for the particulate testing. The following is a brief description of the calibration procedures for each of these important devices.

7.1.1. *Pitot Tubes*

All pitot tubes are the S-type as required by EPA Reference Method 2 (**40 CFR, Part 60, Appendix A, Method 2**). This method contains certain geometric standards for the construction of S-type pitot tubes. All of SEAS pitot tubes are constructed according to these standards. According to the EPA, any pitot tube constructed to these standards will have a coefficient of 0.84 ± 0.02. To ensure the exact value of SEAS pitot tubes all pitot tubes are initially calibrated in SEAS wind tunnel to determine the exact pitot coefficient. This coefficient should not change unless the pitot is physically damaged. Each pitot tube is checked before going to the field to make sure it meets the geometry as specified. Any pitot tube that fails to meet the specifications is not used in the test.

7.1.2. *Differential Pressure Gauges*

SEAS uses several different types of pressure gauges, including oil tube manometers, water tube manometers, magnehelics, and current output electronic load cells. Each of these devices are inspected before taken to the field and are inspected for leaks during each test. The magnehelics and load cells are tested against an incline manometer water gauge to ensure accuracy.

7.1.3. *Orifice*

The flow meter orifice is used to establish isokinetic sampling rates during the test. The orifice is calibrated with the dry gas meter at the same time under the same conditions. The orifice is calibrated over a wide range of flow rates and the arithmetic mean of the orifice calibration is used for sampling purposes. The orifice is recalibrated every time the gas meter is re-certified.

7.1.4. *Dry Gas Meter*

The dry gas meter is calibrated every six months against a spirometer transfer standard. It is again calibrated before and after each use in the field. During the semiannual calibration, a five-point calibration is made at a minimum of one-half inch water column orifice pressure and up to four inches water column orifice pressure. Before and after each test, the dry gas meter is again recalibrated at three repetitions at a representative flow rate experienced during the test. If the final calibration does not agree with the initial calibration within five percent, the calibration which yields the lowest volume of sample pulled is used in the calculations and the dry gas meter is repaired and recalibrated.

7.1.5. *Temperature Sensors*

All temperature sensors used in SEAS sampling program are either mercury in-glass thermometers or type K thermocouples. These thermocouples are physical devices which produce a voltage proportional to the temperature. The thermocouple reading device is calibrated before and after each series of tests to ensure accuracy of ± 2 percent. The calibration of the thermocouple is accomplished by a NIST traceable calibrated reference thermocouple potentiometer system.

7.1.6. Nozzles

The inside diameter of each nozzle is measured to the nearest 0.001 inches prior to its initial use. Upon arriving in the field each nozzle is again measured with a micrometer on three different points on the diameter to ensure its original measurement and that the nozzle is perfectly round. If the difference between the maximum and minimum diameters measured does not exceed 0.003 inches the nozzle is acceptable; otherwise, this nozzle is discarded and another is selected. At the end of each test the nozzles are again remeasured on three different points on the diameter to ensure that during the test the nozzle has not become dented or deformed.

APPENDIX A QUALITY CONTROL OF PARTICULATE TESTING EQUIPMENT

INITIAL METER BOX CALIBRATION

Calibrated By: KDO **BOX #:** S-100 **Date:** 4/21/2004

			Orifice #:	1	Orifice #:	3	Orifice #:	8
		Unit	RUN 1	RUN 2	RUN 1	RUN 2	RUN 1	RUN 2
Meter	ΔH	In. H_2O	0.74	0.75	1.26	1.27	1.47	1.46
	Initial Gas Volume	$Ft.^3$	35.400	88.900	52.200	97.400	45.000	104.300
	Final Gas Volume	$Ft.^3$	43.400	96.900	58.000	103.400	51.000	112.200
	Initial Temp. Out	°F	75	76	74	77	75	77
	Final Temp. Out	°F	75	77	77	77	75	77
	Vacuum	In. Hg	20	20	19	19	18	18
	Ambient Temp.	°F	75	75	75	75	75	75
	Barometric Pressure	In. Hg	30.21	30.21	30.21	30.21	30.21	30.21
	Time	sec	1019	1020	575	592	551	731
	K'		0.3632	0.3632	0.4654	0.4654	0.5052	0.5052
CALCULATIONS								
	Total Meter Gas Volume	Actual $Ft.^3$	8.000	8.000	5.800	6.000	6.000	7.900
	Time	Minutes	16.983	17.000	9.583	9.867	9.183	12.183
	Volume through the Meter	*SDCF without Y*	7.983	7.961	5.790	5.973	5.998	7.868
	Volume through the Orifice	*SDCF*	8.056	8.064	5.825	5.998	6.060	8.039
	Calculated Y	*Dimensionless*	**1.009**	**1.013**	**1.006**	**1.004**	**1.010**	**1.022**
	Difference	*Allowable 0.02*	-0.002	0.002	-0.005	-0.007	0.000	0.011
	Calculated DH@		**1.798**	**1.816**	**1.858**	**1.872**	**1.846**	**1.827**
	Difference	*Allowable 0.2*	-0.057	-0.040	0.002	0.017	-0.009	-0.029

Reference Meter #		Unit	RUN 4	RUN 5	
Field Meter	DH	In. H_2O	4.00	5.00	
	Initial Gas Volume	$Ft.^3$	64.200	78.600	
	Final Gas Volume	$Ft.^3$	74.390	88.600	
	Initial Temp. Out	°F	75	76	
	Final Temp. Out	°F	75	76	
Reference Me	Y	*Dimensionless*	1.000	1.000	
	Initial Gas Volume	$Ft.^3$	258.180	270.740	
	Final Gas Volume	$Ft.^3$	268.550	281.000	
	Initial Temp.	°F	75	76	
	Final Temp.	°F	75	76	
	Barometric Pressure	In. Hg	30.21	30.21	
	Time	sec	572	510	
Calculated Y			1.008	1.014	**1.011**
Difference			-0.003	0.003	
Calculated DH@			1.898	1.930	**1.856**
Difference			0.042	0.075	

Magnehelic Calibrations

Device	Calibration	Delta P	
	Standard	Magnehelic	
Units	inches water	inches water	*Percent*
Reading	Reference	Sample	*Error*
1	0.45	0.44	*-2.2*
2	0.73	0.73	*0.0*
3	1.00	1.00	*0.0*

Allowed Error = 5% of Reading

Thermocouple Calibrations

Device	Calibration	Thermocouple	
	Standard	Detector	
Units	Degrees F.	Degrees F.	*Percent*
Reading	Reference	Sample	*Error*
1	100	98	*-0.4*
2	300	301	*0.1*
3	500	499	*-0.1*

Allowed Error = 1.5% of Absolute Temperature (Degrees Rankin);
Absolute Temperature = Temperature in Degrees Fahrenheit. + 460

Final Meter Box Calibration Check by Critical Orifice

Calibrated By: JCS		Date 6/18/2004	METER BOX #: S-100		
			Orifice # 8		
		Units	RUN 1	RUN 2	RUN 3
Meter	ΔH	In. H_2O	1.49	1.49	1.49
	Initial Gas Volume	Ft.^{3}	558.600	566.700	575.300
	Final Gas Volume	Ft.^{3}	566.600	575.200	584.100
	Initial Temp. Out	°F	72	72	72
	Final Temp. Out	°F	72	72	73
Vacuum (must be > 16.0)		In. Hg	19	19	19
	Ambient Temp.	°F	72	72	72
	Barometric Pressure	In. Hg	30.08	30.08	30.08
	Time	sec	750	792	818
	K'		0.5052	0.5052	0.5052
CALCULATIONS					
Total Meter Gas Volume		Ft.^{3}	8.000	8.500	8.800
	Time	Minutes	12.500	13.200	13.633
Vm = Volume through the Meter		*SDCF without Y*	8.008	8.509	8.801
Vcr = Volume through the Orifice		*SDCF*	8.236	8.697	8.982

			RUN 1	RUN 2	RUN 3	Final Average	Initial Average
	Calculated Y	*Dimensionless*	**1.028**	**1.022**	**1.021**	**1.024**	**1.011**
	Calculated ΔH@		**1.896**	**1.896**	**1.892**	**1.894**	**1.856**

Magnehelic Calibrations

Device	Calibration	Delta P	
	Standard	Magnehelic	
Units	inches water	inches water	*Percent*
Reading	Reference	Sample	*Error*
1	0.50	0.50	*0.0*
2	1.50	1.49	*-0.7*
3	1.95	1.94	*-0.5*

Allowed Error = 5% of Reading

Thermocouple Calibrations

Device	Calibration	Thermocouple	
	Standard	Detector	
Units	Degrees F.	Degrees F.	*Percent*
Reading	Reference	Sample	*Error*
1	100	100	*0.0*
2	300	299	*-0.1*
3	500	501	*0.1*

Allowed Error = 1.5% of Absolute Temperature (Degrees Rankin);
Absolute Temperature = Temperature in Degrees Fahrenheit. + 460

Magnehelic Calibration

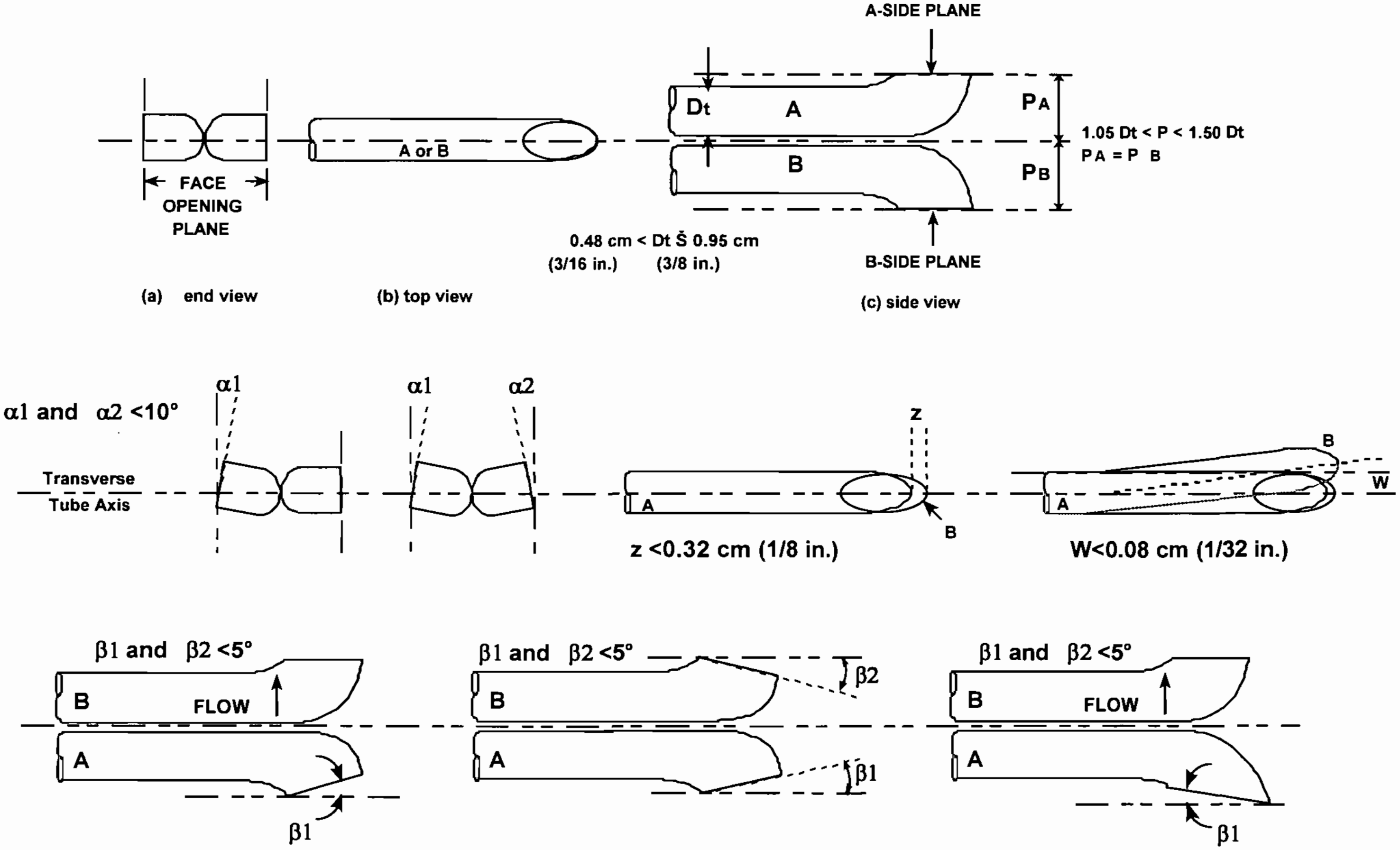
	Box 100						Box 101						Box 100-a					
Ser. No.	**WO21 JY**	**R10908 AG71**	**R98073 14022**	**R977110 5290**	**R96091 6AG447**	**R970227 GJ31**	**R006301 YR66**	**R22D**	**A980821 7883**	**R90051 6G721**	**R981202 CA55**	**R901015 D102**		**R08F2**	**R97020 3**	**R10629J A82**	**R10513 MR42**	**R90124R I119**
Span (in H2O)	**0.25**	**0.5**	**2**	**5**	**10**	**25**	**0.25**	**0.5**	**2**	**5**	**10**	**25**		**0.5**	**2**	**5**	**10**	**25**
Reference Reading @ 0% Span (in H2O)	0.000	0.000	0.00	0.00	0.00	0.00	0.000	0.00	0.00	0.000	0.00	0.00		0.00	0.00	0.00	0.00	0.00
Device Reading (in H2O)	0.000	0.000	0.00	0.00	0.00	0.00	0.000	0.00	0.00	0.000	0.00	0.00		0.00	0.00	0.00	0.00	0.00
% Difference (Allowed = 0.05)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00
Reference Reading @ 50% Span (in H2O)	0.125	0.250	1.00	2.45	5.00	12.50	0.125	0.25	1.00	2.500	4.80	12.50		0.25	1.00	2.50	5.00	13.00
Device Reading (in H2O)	0.125	0.250	1.00	2.50	5.00	12.50	0.125	0.25	0.96	2.500	5.00	12.55		0.25	1.00	2.50	5.00	13.00
% Difference (Allowed = 0.05)	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.04	0.00	0.04	0.00		0.00	0.00	0.00	0.00	0.00
Reference Reading @ 90% Span (in H2O)	0.225	0.45	1.80	4.45	9.00	22.50	0.24	0.44	1.80	4.50	9.00	24.00		0.45	1.80	4.50	9.00	24.00
Device Reading (in H2O)	0.225	0.450	1.80	4.45	9.00	22.50	0.240	0.45	1.80	4.500	9.20	24.00		0.45	1.80	4.50	9.00	24.00
% Difference (Allowed = 0.05)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.02	0.00		0.00	0.00	0.00	0.00	0.00

	Box 102						Box 103					
Ser. No.	**10819 DR2**	**R10902 AG18**	**R50315 EB93**	**810629T A87**		**R10722 MC5**	**R05E**	**R980402 CA34**	**R20202C F1**	**WOBK JM**	**R360**	
Span (in H2O)	**0.25**	**0.5**	**2**	**5**		**25**	**0.25**	**0.5**	**1**	**2**	**5**	**25**
Reference Reading @ 0% Span (in H2O)	0.000	0.000	0.00	0.00		0.00	0.000	0.000	0.00	0.00	0.00	0.00
Device Reading (in H2O)	0.000	0.000	0.00	0.00		0.00	0.000	0.000	0.00	0.00	0.00	0.00
% Difference (Allowed = 0.05)	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reference Reading @ 50% Span (in H2O)	0.130	0.250	1.00	2.40		12.80	0.125	0.245	0.50	1.00	2.40	12.50
Device Reading (in H2O)	0.125	0.255	1.02	2.50		12.50	0.121	0.250	0.50	1.03	2.50	13.00
% Difference (Allowed = 0.05)	0.04	0.02	0.02	0.04		0.02	0.03	0.02	0.00	0.03	0.04	0.04
Reference Reading @ 90% Span (in H2O)	0.240	0.490	1.90	4.70		24.20	0.235	0.440	0.90	1.90	4.90	24.00
Device Reading (in H2O)	0.240	0.490	1.90	4.75		24.00	0.230	0.450	0.90	1.90	5.00	24.00
% Difference (Allowed = 0.05)	0.00	0.00	0.00	0.01		0.01	0.02	0.02	0.00	0.00	0.02	0.00

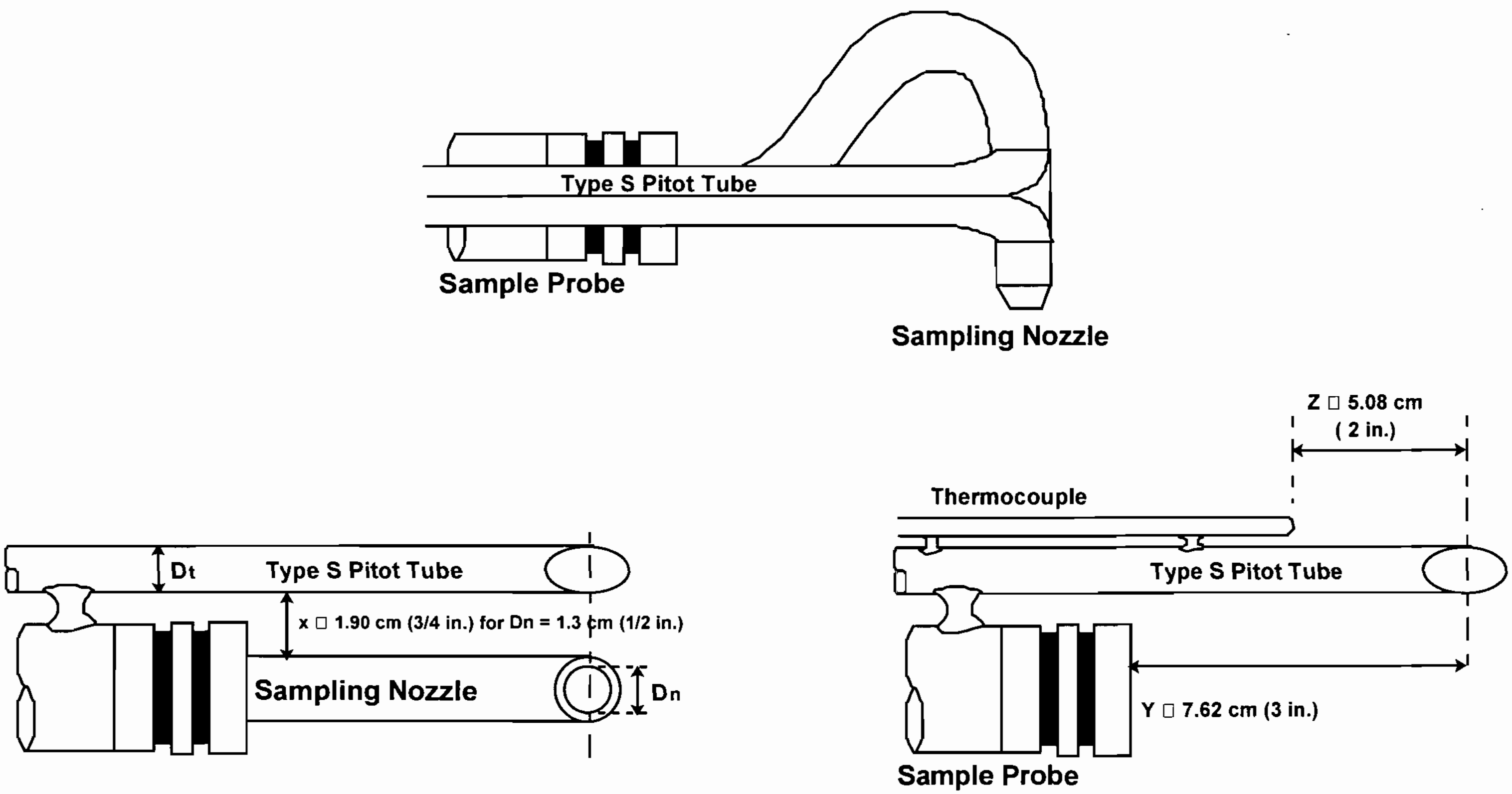
Cailbration Date 06-17-02 By J. RAMPULLA

Type S pitot tube construction details:

a) end view; face opening planes perpendicular to transverse axis.
b) top view; face opening planes parallel to longitudinal axis.
c) side view; both legs of equal length and centerlines coincident, when viewed from both sides.



Sampling Nozzle, Thermocouple, and Probe Configuration



APPENDIX B FIELD DATA SHEETS FOR PARTICULATE TESTING

Sanders Engineering & Analytical Services, Inc.

1568 Leroy Stevens Rd.
Mobile, Al. 36695

Office: (251) 633-4120
Fax: (251) 633-2285

COMPANY GPCo DATE 06-14-04 DGM# S-100

PLANT Crist OPERATOR JK/KW/ET ΔHa ______

UNIT 7 METHOD 17 PROBE (Max Length Allowed) ______

	Run 1	Run 2	Run 3
Nozzle Calibration Pre	.190 / .190 / .190	.190 / .190 / .196	.190 / .190 / .196
Nozzle Calibration Post	.190 / .190 / .190	.190 / .190 / .190	.190 / .190 / .190
AVERAGE	.190	.196	.196
Filter Number	3479	3478	3497
METER READING Final	248.150	285.025	322.800
Initial	~~211.000~~ 211.400	248.500	285.600
Net	36.750	~~37.475~~ 36.525	37.200
LEAK CHECK System Pre (in. Hg / cfm)	15" / 0.001	15" / 0.001	15" / 0.001
System Post (in. Hg / cfm)	10" / 0.001	10" / 0.005	10" / 0.001
Pitot Pre (Impact / Static)	✓ / ✓	✓ / ✓	✓ / ✓
Pitot Post (Impact / Static)	✓ / ✓	✓ / ✓	✓ / ✓
VOLUME OF LIQUID WATER COLLECTED Imp 1 Final / Initial / Net	160 / 100 / 60	170 / 100 / 70	175 / 100 / 75
Imp 2 Final / Initial / Net	100 / 100 / 0	0 / 160 / 0	100 / 100 / 0
Imp 3 Final / Initial / Net	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0
Imp 4 Final / Initial / Net	1875 / 1860 / 15.0	1880 / 1875 / 5.0	1890 / 1880 / 10.0
Total	75.0	75.0	85.0
GAS ANALYSIS O_2	6.0	5.3	5.5
CO_2	12.0	12.0	12.0
CO			
STATIC (in. H_2O)	+2.0	+2.0	+2.0
BAROMETRIC (in. Hg)	29.98	29.98	29.97

Form Revised 8/24/02

Page 1 of ______

Port # / Point#	Time	Gas Meter Volume (Cubic Feet)	Velocity Head ΔP (In. H_2O)	Orifice Head ΔH (In. H_2O)	Temperature °F Stack	Filter	Imp.	Gas Meter	Vac. (In. Hg)
1-1	08:05	211.400	1.48	1.33	335	/	65	85	4.0
2	:07	212.4	1.20	1.08	325		65	85	4.0
3	:09	213.8	1.11	0.99	323		65	85	4.0
4	:11	214.3	1.02	0.90	325		65	85	4.0
5	:13	215.9	1.25	1.11	323		65	85	3.0
6	:15	216.9	1.20	1.06	346		65	85	3.0
2-1	09:20	318.0	2.11	1.87	345		63	85	3.0
2	:22	319.3	1.05	0.93	335		63	86	5.0
3	:24	320.7	1.85	1.64	335		63	86	5.0
4	:26	321.8	1.41	1.25	333		63	85	4.0
5	:28	323.7	1.41	1.25	340		63	85	4.0
6	:30	324.5	1.25	1.11	340		63	85	4.0
3-1	08:33	325.7	2.06	1.82	330		63	83	6.0
2	:35	327.3	1.60	1.40	330		63	83	5.0
3	:37	228.2	1.76	1.56	330		63	83	5.0
4	:39	329.4	1.53	1.35	325		63	83	5.0
5	:41	330.8	1.77	1.57	330		63	83	5.0
6	:43	322.1	1.47	1.30	330		63	83	4.0
4-1	:48	333.2	1.25	1.11	340		63	85	4.0
2	:50	234.2	1.15	1.01	340		63	85	4.0
3	:52	235.3	1.46	1.29	330		62	83	5.0
4	:54	236.5	1.46	1.29	330		62	83	5.0
5	:56	237.6	1.67	1.47	340		62	83	5.0
6	:58	238.7	1.50	1.32	341		62	83	5.0
5-1	09:01	240.0	2.06	1.81	340		62	83	5.0
2	:03	241.7	1.81	1.59	329		62	83	5.0
3	:05	243.0	1.25	1.10	335		62	83	5.0
4	:07	244.0	1.50	1.32	330		62	84	5.0
5	:09	244.9	1.81	1.59	330		62	83	5.0
6	:11	246.1	2.20	1.93	327		62	83	6.0
	:								
Stop	09:13	248.150							
	:								

Form Revised 8/24/02

Company: GPCo Date: 06-14-04 Page ______

Site: Smith Unit 7 Run #: 1 Of ______

Port # / Point#	Time	Gas Meter Volume (Cubic Feet)	Velocity Head ΔP (In. H_2O)	Orifice Head ΔH (In. H_2O)	Temperature °F Stack	Filter	Imp.	Gas Meter	Vac. (In. Hg)
1-1	09:45	248.500	2.20	1.90	340	—	61	81	5.0
2	:47	249.9	2.06	1.81	340		61	81	6.0
3	:49	250.9	1.81	1.59	345		61	81	6.0
4	:51	251.9	1.54	1.35	340		61	81	6.0
5	:53	252.2	1.81	1.59	340		61	81	6.0
6	:55	254.5	2.06	1.81	340		61	81	6.0
2-1	:58	255.3	1.15	1.01	340		61	81	4.0
2	10:00	257.2	1.15	1.01	340		61	81	4.0
3	:02	258.1	1.53	1.35	335		61	81	4.0
4	:04	259.1	1.68	1.47	330		61	81	4.0
5	:06	260.3	1.50	1.32	330		61	81	4.0
6	:08	262.1	1.50	1.32	330		61	81	4.0
3-1	:11	263.3	2.06	1.81	340		61	81	4.0
2	:13	264.5	1.60	1.41	340		61	81	4.0
3	:15	266.1	1.85	1.64	330		61	81	4.0
4	:17	267.3	1.81	1.59	330		61	81	4.0
5	:19	268.4	1.85	1.64	330		61	81	4.0
6	:21	269.5	1.60	1.41	340		61	81	4.0
4-1	:25	271.2	1.40	1.26	330		61	81	4.0
2	:27	272.2	0.90	0.81	330		61	79	4.0
3	:29	273.2	1.40	1.26	330		61	79	4.0
4	:31	274.6	1.40	1.26	330		61	79	4.0
5	:33	275.6	1.60	1.41	330		61	79	4.0
6	:35	277.1	1.40	1.26	330		61	79	4.0
5-1	:37	278.2	1.25	1.11	330		61	79	4.0
2	:40	279.3	1.20	1.03	340		61	79	5.0
3	:42	280.9	1.25	1.11	330		61	79	5.0
4	:44	281.7	1.25	1.11	330		61	79	5.0
5	:46	282.7	1.25	1.11	330		61	79	5.0
6	:48	283.8	1.25	1.11	330		61	79	5.0
	:								
Stop	10:50	285.025							
	:								

Form Revised 8/24/02

Company: Gulf Power Date: 06-14-04 Page ____

Site: Crist Unit 7 Run #: 2 Of ____

Port # / Point#	Time	Gas Meter Volume (Cubic Feet)	Velocity Head ΔP (In. H_2O)	Orifice Head ΔH (In. H_2O)	Temperature °F Stack	Filter	Imp.	Gas Meter	Vac. (In. Hg)
1-1	11 : 12	285.600	1.25	1.11	345	/	61	81	4.0
2	:14	286.9	1.25	1.11	345		61	81	4.0
3	:16	287.8	0.90	0.81	345		61	81	4.0
4	:18	288.9	0.90	0.81	345		61	81	4.0
5	:20	290.1	1.25	1.11	340		61	80	3.0
6	:22	291.3	1.25	1.11	340		61	80	3.0
2-1	:25	292.4	1.60	1.41	340		61	80	3.0
2	:27	293.5	1.00	0.90	335		61	81	3.0
3	:29	294.5	1.40	1.26	340		61	81	3.0
4	:31	295.6	1.40	1.26	340		61	81	3.0
5	:33	296.5	1.50	1.32	345		61	81	3.0
6	:35	298.1	1.40	1.26	340		61	81	3.0
3-1	11 :40	299.400	2.20	1.90	340		61	81	5.0
2	:42	301.2	1.40	1.26	340		61	81	4.0
3	:44	302.5	1.77	1.57	335		61	81	5.0
4	:46	303.1	1.11	0.99	335		61	81	5.0
5	:48	304.5	1.47	1.30	335		61	81	5.0
6	:50	305.8	1.80	1.59	335		61	81	5.0
4-1	:53	307.2	1.40	1.26	340		61	81	5.0
2	:55	308.4	1.53	1.35	340		61	81	5.0
3	:57	309.7	1.50	1.32	335		61	81	5.0
4	:59	310.4	1.53	1.35	340		61	81	5.0
5	12 :01	312.0	2.06	1.82	340		61	81	5.0
6	:03	313.7	1.50	1.32	345		61	81	5.0
5-1	:06	314.9	2.06	1.82	340		61	82	5.0
2	:08	316.4	2.06	1.82	334		61	83	5.0
3	:10	317.8	1.80	1.58	340		62	83	5.0
4	:12	317.9	1.80	1.58	330		62	83	5.0
5	:14	319.2	1.25	1.11	330		62	83	5.0
6	:16	321.6	1.25	1.11	330		62	83	
	:								
Stop	12 :18	322.600							
	:								

Form Revised 8/24/02

Company: GPCO Date: 06-14-05 Page ______

Site: Crist unit 7 Run #: 3 Of ______

LABORATORY ANALYSIS & CHAIN OF CUSTODY

COMPANY/PLANT: GPCO Crist 7

UNIT #: 7 DATE OF TEST: 6-14-04 TYPE OF TEST: ☐ M-5 ☑ M-17 ☐ OTHER ____

SAMPLE #	RELINQUISHED BY:	RECEIVED BY:	TIME:	DATE:	REASON FOR CHANGE
3479	JBR	[illegible]	16:00	6-14-04	Analysis
3478					
3177					

RUN # 1	FILTER # 3479	BEAKER 12 WASH (ML)	RUN #	FILTER #	BEAKER WASH (ML)
FINAL WEIGHT	118.0	70496.4	FINAL WEIGHT		
INITIAL WEIGHT	111.4	70492.7	INITIAL WEIGHT		
DIFFERENCE	6.6	3.7	DIFFERENCE		
	CORRECTED TOTAL WEIGHT	10.3		CORRECTED TOTAL WEIGHT	
RUN # 2	FILTER # 3478	BEAKER 44 WASH (ML)	RUN #	FILTER #	BEAKER WASH (ML)
FINAL WEIGHT	125.8	62171.5	FINAL WEIGHT		
INITIAL WEIGHT	118.1	62165.6	INITIAL WEIGHT		
DIFFERENCE	7.7	5.9	DIFFERENCE		
	CORRECTED TOTAL WEIGHT	13.6		CORRECTED TOTAL WEIGHT	
RUN # 3	FILTER # 3477	BEAKER 75 WASH (ML)	RUN #	FILTER #	BEAKER WASH (ML)
FINAL WEIGHT	116.9	62339.0	FINAL WEIGHT		
INITIAL WEIGHT	119.6	62330.8	INITIAL WEIGHT		
DIFFERENCE	-2.7	8.2	DIFFERENCE		
	CORRECTED TOTAL WEIGHT	5.5		CORRECTED TOTAL WEIGHT	

WASH SOLVENT BLANK (ML)		BEAKER # WASH (ML)
FINAL WEIGHT		
INITIAL WEIGHT		
DIFFERENCE		
CORRECTED TOTAL WEIGHT		

APPENDIX C SAMPLE CALCULATIONS

Sample Calculations, Run 1
GULF POWER COMPANY
PLANT CRIST, UNIT 7
SOOT BLOWING OPERATIONS

Absolute Stack Pressure (inches Mercury)

$$P_S = P_{bar} + \frac{\overline{P_g}}{13.6}$$

P_g = Stack Static Pressure (inches Water) = 2.00
P_{bar} = Barometric Pressure (inches Mercury) = 29.98
P_s = 30.13

Absolute Pressure at the Dry Gas Meter (inches Mercury)

$$P_m = P_{bar} + \frac{\overline{\Delta H}}{13.6}$$

P_{bar} = Barometric Pressure (inches Mercury) = 29.98
ΔH = Average pressure difference of orifice (inches Water) = 1.35
P_m = 30.08

Average Stack Gas Velocity (feet per second)

$$V_s = K_p C_p \overline{\sqrt{\Delta P}} \sqrt{\frac{\overline{T_s}}{M_s P_s}}$$

Kp = Pitot tube constant $\sqrt{\frac{(\text{lb/lb - mole})\ (\text{inches Hg})}{(°\text{R})\ (\text{inches H2O})}}$ = 85.49

C_p = Pitot tube coefficient (dimensionless) = 0.84
$\overline{\sqrt{\Delta P}}$ = Velocity head of stack gas (inches H2O) = 1.2155
Ts = Average absolute temperature of stack, degrees Rankin = 792.9
M_s = Molecular weight of stack gas; wet basis (lb/lb mole) = 29.08
P_s = Absolute stack pressure (inches Mercury) = 30.13
V_s = 83.04

Volume of Gas Sampled Measured by Dry Gas Meter

(corrected to standard conditions, SDCF)

$$Vm(Std) = K_1 V_m Y \left[\frac{P_{bar} + \frac{\overline{\Delta H}}{13.6}}{\overline{T_m}} \right]$$

K_1 = Degrees R/inches Mercury =	17.64
V_m = Volume of gas sample as measured by dry gas meter (actual cubic feet) =	36.750
Y = Dry gas meter calibration factor (dimensionless) =	1.011
P_{bar} = Barometric Pressure (inches Mercury) =	29.98
Δ H = Average pressure difference of orifice (inches H2O) =	1.35
Ts = Average absolute temperature of the dry gas, degrees Rankin =	543.7
$V_{m\,(Std)}$ =	36.261

Volume of Water Vapor in Gas Sample

(corrected to standard conditions, SDCF)

$$V_{w\,(Std)} = 0.04707\ V_{lc}$$

V_{lc} = Total volume of liquid collected in impingers and silica gel (milliliters) =	75.0
$V_{w\,(Std)}$ =	3.530

Water Vapor in the Gas Stream proportion by volume (dimensionless)

$$B_{ws} = \frac{V_{w(Std)}}{V_{m(Std)} + V_{w(Std)}}$$

$V_{w\,(std)}$ = Volume of water in gas sample (corrected to standard conditions) =	3.530
$V_{m(std)}$ = Volume of sample measured by dry gas meter (standard conditions) =	36.261
B_{ws} =	0.089

Molecular Weight of Stack Gas (dry basis, lb/lb mole)

$$M_d = 0.44(\%CO_2) + 0.32(\%O_2) + 0.28(\%N_2 + \%CO)$$

$\%CO_2$ = Number percent by volume (dry basis from gas analysis) =	12.00
$\%O_2$ = Number percent by volume (dry basis from gas analysis) =	6.00
$\%N_2$+%CO = Number percent by volume (dry basis from gas analysis) =	82.00
M_d =	30.16

Molecular Weight of Stack Gas (wet basis, lb/lb mole)

$$M_s = M_d(1 - B_{ws}) + 18(B_{ws})$$

M_d = Molecular weight of stack gas (dry basis, lb/lb mole) =	30.16
B_{ws} = Water vapor in the gas stream (proportion by volume, dimensionless) =	0.089
M_s =	29.08

Volumetric Flow Rate (actual cubic feet per minute)

$$Q_a = (V_s)(A_s)(60)$$

V_s = Average stack gas velocity (feet per second) =	83.04
A_s = Cross sectional area of stack (feet squared) =	366.263
Q_a =	1,114,378

Volumetric Flow Rate (standard dry cubic feet per minute)

$$Q_s = Q_a(1 - B_{ws})\frac{(528)}{\overline{T_s}}\frac{(P_s)}{29.92}$$

Q_a = Volumetric flow rate (actual cubic feet per minute) =	1,114,378
B_{ws} = Water vapor in the gas stream (proportion by volume, dimensionless) =	0.089
Ts = Average absolute temperature of stack, degrees Rankin =	792.9
P_s = Absolute stack pressure (inches Mercury) =	30.13
Q_s =	1,824,841

Volumetric Flow Rate (standard wet cubic feet per minute)

$$Q_{sw} = Q_a\frac{(528)}{\overline{T_s}}\frac{(P_s)}{29.92}$$

Q_a = Volumetric flow rate (actual cubic feet per minute) =	1,114,378
Ts = Average absolute temperature of stack, degrees Rankin =	792.9
P_s = Absolute stack pressure (inches Mercury) =	30.13
Q_{sw} =	1,222,871

Particulate Mass Rate (pounds per hour)

$$PMR = (Cs)\,(Qs)\,\frac{(60)}{7000}$$

Cs =Polutant concentration (grains per standard dry cubic foot) =	0.0044
Q_a = Volumetric flow rate (standard dry cubic feet per minute) =	1,824,841
PMR =	41.78

Particulate Concentration (grains per standard dry cubic foot)

$$C_s = 0.0154\,\frac{M_n}{V_{m(Std)}}$$

Mn = Total amount ofPolutant collected (milligrams) =	10.3
$V_{m(Std)}$ = Volume of stack gas sampled (corrected to standard conditions) =	36.261
C_s =	0.0044

Particulate Concentration (grains per actual cubic foot)

$$C_a = 0.0154\,\frac{M_n}{V_{n\,(actual)}}$$

Mn = Total amount ofPolutant collected (milligrams) =	10.3
$V_{n\,(actual)}$ = Volume sampled at stack conditions (actual cubic feet) =	59.366
C_a =	0.0027

Percent of Isokinetic Sampling

$$I = \frac{100\ V_n}{(60)\ \varnothing\ V_s\ A_n}$$

V_n = Volume sampled at stack conditions through nozzle (actual cubic feet) =	59.366
V_s = Average stack gas velocity (feet per second) =	83.04
A_n = Cross-sectional area of nozzle (feet squared) =	0.000197
$\varnothing$ = Sampling Time (minutes) =	60
I =	100.9

Volume of Gas Sampled Through Nozzle (actual cubic feet)

$$V_n = \left[(0.002669)(V_{lc}) + Y\frac{V_m}{T_m}\left(P_{bar} + \frac{\overline{\Delta H}}{13.6}\right)\right]\frac{\overline{T_s}}{P_s}$$

V_{lc} = Total volume of liquid collected in impingers and silica gel (milliliters) =	75.0
Y = Dry gas meter calibration factor (dimensionless) =	1.011
V_m = Volume of gas sample as measured by dry gas meter (actual cubic feet) =	36.750
Tm = Average absolute temperature of dry gas meter, degrees Rankin =	543.7
P_{bar} = Barometric Pressure (inches Mercury) =	29.98
ΔH = Average pressure difference of orifice (inches Water) =	1.35
Ts = Average absolute temperature of stack, degrees Rankin =	792.9
P_s = Absolute stack pressure (inches Mercury) =	30.13
V_n =	59.366

Emission Rate in Pounds Per Million Btu (EPA Oxygen F Factor)

$$E = C_d\, F_{O2}\left(\frac{20.9}{20.9 - \%O_2}\right)$$

Cd = Pollutant concentration (pounds per standard dry cubic foot) =	0.0000006
F_{O2} = Oxygen based F factor (SDCF/mmBtu for bituminous coal) =	9780
$\%O_2$ = Number percent by volume (dry basis from gas analysis) =	6.0
E_{O2} =	0.00857

Unit Operating Rate-Million Btu per Hour

$$UOR = \left(\frac{PMR}{E_{O2}}\right)$$

E_{O2} = Emission Rate in Pounds Per Million Btu (EPA Oxygen F Factor) =	0.00857
PMR = Pollutant Mass Rate (pounds per hour) =	41.78
UOR=	4874

APPENDIX D OPERATIONAL DATA

Gulf Power Plant Crist Unit 7
CAM Baseline Test Notes
Sootblowing Testing 06/14/04

Run #1

Start Time		Notes
CDT	**CEMS**	No operational problems noted.
09:05	18:08	NOTE: CEMS time, not Central Daylight Time (CDT), is used on Sander's test report.
Stop Time		
CDT	**CEMS**	Blowers blown 41L and 41R
10:13	09:13	

Run #2

Start Time		Notes
CDT	**CEMS**	No operational problems noted.
10:45	09:45	
Stop Time		Blowers blown 40L and 40R
CDT	**CEMS**	
11:50	10:50	

Run #3

Start Time		Notes
CDT	**CEMS**	No operational problems noted.
12:12	11:12	Blowers blown 42L
Stop Time		Superheater tube leak discovered during run.
CDT	**CEMS**	
13:18	12:18	

Crist 7
CAM Baseline Test

Maximum Allowable Heat Input: 6,406.4 mmBtu/hr

Soot Blow June 14, 2004

Run #	Load Gross MW	Start Time	End Time	Duration (Hours)	coal flow from LDMS (tons)	Coal Analysis Btu / lb	LDMS results mmBtu's/hr
1	501	08:05	09:13	1.13	222.80	11588	4556.1
2	501	09:45	10:50	1.08	213.50	11630	4584.0
3	500.5	11:12	12:18	1.10	218.40	11487	4561.4
	501					**Average**	4567.2
						Percent of Max Allowable	71%
						Load Limit if % < 90%	551

6406.4

CEMS OPACITY DATA
Crist 7
CAM Baseline

Date	CEM Hour	Minutes									
		00	6	12	18	24	30	36	42	48	54
Sootblow Testing											
06/14/04	8	4.9	4.9	4.8	4.9	5.0	4.9	5.0	5.0	4.9	5.0
06/14/04	9	4.9	4.9	5.0	5.0				5.1	5.1	5.1
06/14/04	10	5.1	5.2	5.1	5.1	5.2	5.2	5.3	5.3	5.3	5.4
06/14/04	11		5.5	5.5	5.6	5.6	5.6	5.7	5.6	5.7	5.9
06/14/04	12	5.8	5.8	5.9	5.9	6.0					

Crist Plant Particulate Compliance Test Control Room Data

Unit 7 Date 6/14/04

Check one: X Sootblowing Steady-State (no sootblowing)

Unit Operator : Diamond

Run	CEMS Time	Pulverizer Coal Integrators (x 100 pounds) A	B	C	D	E	F	Generation Digital Meter MW	Gross Generation Integrator MWhr	Main Steam Total Flow (x 10e6 lb/hr)	Boiler Air Flow (x 10e6 lb/hr)	Excess O2 Econ Outlet % A	Excess O2 Econ Outlet % B	Opacity 6 min Avg %	ID Fan Amps A (C)	ID Fan Amps B (D)	Gas Temp Air Htr Outlet deg F A	Gas Temp Air Htr Outlet deg F B	Soot Blowing Status	Data ~~taken~~ by (~~initials~~) 54	R(
#1 Start	0805							287398	500	3559	4536	3.8	3.1	4.85	390 408	392 408	316	298		997	98[illegible]
#1 End	0913							287990	502	3546	4497	3.7	3.0	4.97			316	296		1000	98[illegible]
															384 406	389 408					
#2 Start	0945							288225	502	3555	4555	3.9	3.1	5.15	390 410	388 415	309	292		999	985
#2 End	10:50							288830	500	3533	4554	4.0	3.1	5.30	390	390	312	292		998	984
															409	411					
#3 Start	1112							288965	501	3540	4520	3.9	3.0	5.43	390 406	393 411	313	293		999	984
#3 End	1218							289528	500	3520	4522	3.9	3.1	5.85	388	392	315	293		1000	984
															410	412					

Operational Comments

Run		A	B	C	D	E	F	
Run #1	start	658997	470146	414666	663800	665400	428044	Sootblowers - 41L / 41R
	stop	659038	470187	414707	663841	665442	428086	
Run #2	start	659055	470204	414724	663858	665458	428103	Sootblowers - 40L / 40R
	stop	659095	470244	414764	663898	665498	428143	
Run #3	start	659105	470255	414775	663909	665509	428154	Sootblowers - 42L /
	stop	659145	470294	414815	~~[illegible]~~ 663949	665549	428193	

Inside Operator S. Diamond

outside Operator (Coal Samples) M. Daniels

Laboratoryman (Ash Samples) C. Flemming

Electrician (ESP Readings) T. Tolbert / D. Williams

[redacted]LF POWER
A SOUTHERN COMPANY

[redacted] Plant Crist
Unit 7
Precipitator Report

Date: [redacted]/14/2004
Start Ti[redacted] 8:05a
Run 1

Precipitator Readings										
	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	451	451	450	451	451	449	449	448	448	449
Primary Current	79.8	219.9	132.2	218.3	219.6	40.5	197.9	191.7	218.6	218.7
Total Power	34	98	50	96	95	14	84	75	90	92
Secondary kV	61.9	64.8	53.9	59.7	62.4	54.8	57.2	54.2	59.9	57.7
Secondary mA	475.4	1299.9	825.3	1299.9	1298.7	277.4	1133.8	1056.1	1299.6	1299.4
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	9	5	2	0	0	11	8	1	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	450	450	449	449	449	448	447	446	446	447
Primary Current	58.7	218.1	220.0	217.4	219.1	45.6	163.5	217.8	218.7	217.3
Total Power	23	95	95	94	94	17	66	89	92	91
Secondary kV	57.3	59.2	61.9	62.1	61.8	57.8	57.0	53.2	59.7	59.8
Secondary mA	363.7	1299.2	1299.8	1300.1	1299.8	272.0	1034.7	1299.8	1299.9	1299.8
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	10	1	1	0	0	11	6	0	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	449	449	448	448	449	447	447	446	446	447
Primary Current	51.5	218.5	221.3	218.8	217.5	40.2	217.6	203.3	218.0	219.0
Total Power	18	94	92	91	92	15	93	83	92	91
Secondary kV	56.5	60.9	57.8	59.2	61.0	57.2	60.8	64.5	59.8	58.8
Secondary mA	312.5	1300.0	1299.8	1299.8	1299.9	221.8	1299.2	1225.4	1299.9	1299.9
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	9	2	0	0	1	10	3	7	0	0

[redacted]F POWER
A SOUTHERN COMPANY

Date: [redacted]4/2004
STOP Tim[redacted] 9:13Am
Run 1

Plant Crist
Unit 7
Precipitator Report

Precipitator Readings										
	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	451	450	450	450	450	450	450	448	449	449
Primary Current	63.1	220.1	218.5	218.3	219.7	65.1	156.0	219.5	218.4	219.1
Total Power	25	98	97	96	96	25	62	91	90	92
Secondary kV	59.7	64.7	64.5	59.8	62.5	56.2	56.0	58.1	60.1	58.0
Secondary mA	387.4	1300.2	1299.8	1300.1	1299.2	344.3	986.9	1299.9	1299.6	1299.7
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	11	2	0	0	0	11	5	1	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	450	450	449	449	450	450	450	448	448	449
Primary Current	54.0	218.7	220.0	217.3	219.0	48.1	110.9	189.5	218.7	217.3
Total Power	21	96	95	94	93	18	40	76	92	91
Secondary kV	57.3	59.7	62.1	62.3	61.9	58.9	50.5	52.0	59.6	59.6
Secondary mA	336.7	1300.0	1299.5	1299.7	1299.8	293.4	597.7	1114.8	1299.7	1299.8
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	12	1	0	0	0	12	5	5	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	449	449	448	447	449	449	448	447	447	447
Primary Current	57.4	219.2	221.0	218.8	217.1	38.6	149.0	118.8	217.9	219.1
Total Power	21	95	92	92	92	14	59	48	91	90
Secondary kV	57.3	61.3	58.2	59.5	61.3	56.6	55.6	56.9	59.7	58.7
Secondary mA	349.9	1299.8	1300.1	1299.8	1300.5	223.3	973.6	785.6	1299.6	1299.6
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	10	2	0	1	0	10	6	10	0	0

GULF POWER
A SOUTHERN COMPANY

Plant Crist
Unit 7
Precipitator Report

Date: 6/[illegible]/2004
Start Time: [redacted] 9:45 Am
Run 2

Preciptator Readings

	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	451	451	450	450	450	450	450	448	449	449
Primary Current	68.6	220.0	218.7	218.3	219.6	42.4	79.9	219.5	218.3	219.2
Total Power	30	98	97	96	96	31	13	92	91	93
Secondary kV	58.2	64.9	64.9	59.9	62.6	56.6	48.0	58.6	60.8	58.7
Secondary mA	410.1	1299.0	1300.4	1299.4	1299.2	288.6	681.1	1299.8	1298.9	1300.1
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	10	0	0	0	0	11	2	1	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	450	450	449	449	449	447	447	446	446	446
Primary Current	65.6	218.7	219.7	216.9	218.9	28.7	67.5	217.9	198.6	217.3
Total Power	35	96	95	94	94	20	54	89	93	91
Secondary kV	58.5	60.0	62.7	62.6	62.0	57.6	45.8	53.6	57.1	59.9
Secondary mA	363.8	1299.9	1299.4	1300.0	1299.8	270.1	446.3	1235.8	1283.5	1184.7
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	9	0	0	0	0	12	2	0	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	449	448	448	447	449	448	448	446	446	447
Primary Current	61.0	218.9	221.2	219.3	217.2	21.8	107.2	155.6	218.2	219.1
Total Power	20	95	93	93	93	14	94	47	92	91
Secondary kV	56.4	61.9	59.4	60.6	61.8	56.3	51.4	59.5	60.0	58.9
Secondary mA	359.0	1300.0	1151.4	1299.8	1299.7	207.8	593.0	707.2	1299.5	1299.7
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	9	1	1	0	0	11	5	8	0	0

G[redacted]LF POWER
A SOUTHERN COMPANY

[redacted]lant Crist
Unit 7
Precipitator Report

Date: [redacted]/2004
Stop Time [redacted] 10:50 Am
Run 2

Precipitator Readings

	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	450	450	449	449	450	449	449	448	448	449
Primary Current	86.9	219.6	218.3	218.4	219.8	65.4	151.7	219.6	218.2	219.2
Total Power	38	97	96	96	95	25	60	91	91	93
Secondary kV	61.0	64.0	64.3	59.8	62.5	56.2	53.4	58.1	60.4	58.4
Secondary mA	453.6	1299.8	1300.0	1299.9	1299.2	320.8	930.9	1299.8	1299.8	1299.7
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	10	6	0	0	0	9	9	0	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	451	451	450	450	450	448	447	446	446	447
Primary Current	57.1	218.2	219.7	217.2	219.2	48.3	172.2	217.8	218.7	217.2
Total Power	21	96	95	94	94	17	70	89	92	91
Secondary kV	56.8	59.5	62.0	62.2	61.9	58.0	57.0	53.1	59.8	59.9
Secondary mA	340.2	1299.5	1298.9	1299.6	1299.9	265.7	1059.0	1300.0	1300.0	1299.9
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	9	2	0	0	0	9	10	1	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	449	449	448	448	449	447	447	446	446	447
Primary Current	53.0	179.1	220.9	182.6	217.2	43.6	217.1	136.4	218.1	218.9
Total Power	20	75	92	75	92	17	93	50	92	91
Secondary kV	54.9	59.0	58.6	58.2	61.3	57.0	60.7	57.7	59.9	58.8
Secondary mA	297.0	1064.1	1299.8	1113.4	1299.8	251.8	1299.0	824.9	1300.1	1299.7
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	11	8	0	1	0	10	1	9	0	0

G[redacted]F POWER
A SOUTHERN COMPANY

[redacted]lant Crist
Unit 7
Precipitator Report

Date: 6/14/2004
Start Time: [redacted] 1211.2 pm
Rm 3

Precipitator Readings

	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	451	451	450	450	451	449	449	447	448	449
Primary Current	61.2	219.7	218.5	218.2	219.9	70.4	186.1	219.4	218.5	219.3
Total Power	30	97	96	96	95	28	76	91	91	93
Secondary kV	61.4	62.1	64.1	59.7	62.5	57.4	53.0	58.1	60.1	58.2
Secondary mA	463.8	1232.9	1299.4	1299.6	1299.0	427.9	771.1	1299.8	1298.8	1299.3
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	9	0	0	0	0	10	7	0	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	450	450	449	449	450	448	448	447	447	447
Primary Current	65.7	218.3	219.5	216.9	219.1	35.7	157.7	217.7	218.6	217.3
Total Power	26	94	95	94	93	13	64	89	92	91
Secondary kV	56.5	57.8	61.5	61.5	61.9	57.1	52.0	53.1	59.5	59.6
Secondary mA	390.6	1299.4	1300.1	1299.7	1300.1	262.1	671.2	1299.6	1299.6	1300.0
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	11	1	0	0	0	11	6	0	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	449	449	448	447	449	447	447	446	446	447
Primary Current	57.4	219.2	221.1	218.9	217.3	43.1	217.9	158.3	218.0	219.0
Total Power	21	95	93	92	93	17	94	61	92	91
Secondary kV	56.9	61.0	58.1	59.1	61.1	57.0	61.0	57.1	59.8	58.7
Secondary mA	308.1	1299.8	1299.8	1299.7	1299.8	238.0	1299.7	923.5	1299.4	1299.9
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	9	3	0	0	0	12	2	3	0	0

GULF POWER
A SOUTHERN COMPANY

Plant Crist
Unit 7
Precipitator Report

Date: 6/14/2004
STOP Time [illegible] 1:18pm
Run 3

Precipitator Readings

	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	451	451	450	450	450	450	450	448	448	449
Primary Current	82.2	219.9	218.6	218.3	219.9	45.7	91.6	219.3	218.8	219.2
Total Power	32	97	96	96	95	16	31	91	91	92
Secondary kV	61.7	63.3	63.9	59.6	62.2	53.7	48.3	57.7	59.9	58.2
Secondary mA	465.6	1300.0	1299.8	1299.8	1299.0	269.3	532.5	1300.0	1300.0	1300.5
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	10	0	1	0	0	9	8	0	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	450	450	449	449	449	449	449	447	447	447
Primary Current	55.4	218.7	219.2	217.2	219.1	34.8	85.6	217.2	218.4	217.0
Total Power	24	95	94	94	93	13	26	80	92	91
Secondary kV	56.6	58.3	61.1	61.9	61.7	54.6	49.7	52.7	59.1	59.5
Secondary mA	326.2	1299.7	1299.5	1299.7	1299.9	207.3	534.1	1299.7	1299.8	1299.8
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	10	0	0	0	0	11	3	1	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	448	448	447	447	448	448	448	446	446	447
Primary Current	76.8	218.6	221.0	218.8	196.5	31.3	106.7	143.0	217.6	219.1
Total Power	30	94	92	91	92	11	34	86	91	90
Secondary kV	57.8	60.7	58.0	59.3	59.3	54.8	51.2	54.3	59.4	58.6
Secondary mA	419.0	1299.9	1299.6	1299.9	1180.0	190.2	636.6	741.5	1299.9	1300.0
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	8	3	1	0	0	10	5	1	1	0

General Test Laboratory
P.O. Box 2641
Birmingham, Alabama 35291
(205) 664 - 6081

CERTIFICATE OF ANALYSIS

TO: Kevin Beaty
Gulf Power Co.

Customer Account : CRI07SP
Sample Date : 14-Jun-04
Laboratory Account : CRI07SP
Received Date : 16-Jun-04

Description : Gulf Power Plant Crist Unit 7

PCT-SB Run 1

Laboratory ID Number : AI16489

Test Name	Reference	Result	Units
Dry Basis			
Ash, Dry	ASTM D 5142	4.95	% By Weight
Heat of Combustion, Dry	ASTM D 5865	13300	Btu/lb
Carbon, Dry Basis	ASTM D 5373	76.40	% By Weight
Hydrogen, Dry Basis	ASTM D 5373	4.88	% By Weight
Nitrogen, Dry Basis	ASTM D 5373	1.45	% By Weight
Oxygen, Dry Basis	ASTM D 3176	11.87	% By Weight
Carbon Fixed, Dry	ASTM D 3172	57.67	% By Weight
Volatiles, Dry Basis	ASTM D 5142	37.38	% By Weight
Sulfur, Dry Basis	ASTM D 4239	0.45	% By Weight
As Received			
Moisture, Total	ASTM D 2013	12.87	% By Weight
Ash, As Received	ASTM D 5142	4.31	% By Weight
Heat of Combustion, As Received	ASTM D 5865	11588	Btu/lb
Carbon, As Received	ASTM D 5373	66.57	% By Weight
Hydrogen, As Received	ASTM D 5373	4.25	% By Weight
Nitrogen, As Received	ASTM D 5373	1.26	% By Weight
Oxygen, As Received	ASTM D 3176	10.34	% By Weight
Carbon Fixed, As Received	ASTM D 3172	50.25	% By Weight
Volatiles, As Received	ASTM D 5142	32.57	% By Weight
Sulfur, As Received	ASTM D 4239	0.39	% By Weight
General			
Heat of Combustion, MAF	ASTM D 5865	13993	Btu/lb
Sulfur, lbs/mmBTU	ASTM D 3180	0.338	lbs/mmBTU

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments:

CC: John Dominey

Quality Control ____________________ **Supervision**____________________ **Date :** 7/2/2004

smk/coa

General Test Laboratory
P.O. Box 2641
Birmingham, Alabama 35291
(205) 664 - 6081

CERTIFICATE OF ANALYSIS

TO: Kevin Beaty
Gulf Power Co.

Customer Account : CRI07SP
Sample Date : 14-Jun-04
Laboratory Account : CRI07SP
Received Date : 16-Jun-04

Description : Gulf Power Plant Crist Unit 7

PCT-SB Run 2

Laboratory ID Number : AI16490

Test Name	Reference	Result	Units
Dry Basis			
Ash, Dry	ASTM D 5142	5.09	% By Weight
Heat of Combustion, Dry	ASTM D 5865	13307	Btu/lb
Carbon, Dry Basis	ASTM D 5373	75.98	% By Weight
Hydrogen, Dry Basis	ASTM D 5373	4.94	% By Weight
Nitrogen, Dry Basis	ASTM D 5373	1.45	% By Weight
Oxygen, Dry Basis	ASTM D 3176	12.08	% By Weight
Carbon Fixed, Dry	ASTM D 3172	57.46	% By Weight
Volatiles, Dry Basis	ASTM D 5142	37.45	% By Weight
Sulfur, Dry Basis	ASTM D 4239	0.46	% By Weight
As Received			
Moisture, Total	ASTM D 2013	12.60	% By Weight
Ash, As Received	ASTM D 5142	4.45	% By Weight
Heat of Combustion, As Received	ASTM D 5865	11630	Btu/lb
Carbon, As Received	ASTM D 5373	66.41	% By Weight
Hydrogen, As Received	ASTM D 5373	4.32	% By Weight
Nitrogen, As Received	ASTM D 5373	1.27	% By Weight
Oxygen, As Received	ASTM D 3176	10.56	% By Weight
Carbon Fixed, As Received	ASTM D 3172	50.22	% By Weight
Volatiles, As Received	ASTM D 5142	32.73	% By Weight
Sulfur, As Received	ASTM D 4239	0.40	% By Weight
General			
Heat of Combustion, MAF	ASTM D 5865	14021	Btu/lb
Sulfur, lbs/mmBTU	ASTM D 3180	0.346	lbs/mmBTU

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments:

CC: John Dominey

Quality Control ____________________ **Supervision**________________________ Date : 7/2/2004

smk/coa

General Test Laboratory
P.O. Box 2641
Birmingham, Alabama 35291
(205) 664 - 6081

CERTIFICATE OF ANALYSIS

TO: Kevin Beaty
Gulf Power Co.

Customer Account : CRI07SP
Sample Date : 14-Jun-04
Laboratory Account : CRI07SP
Received Date : 16-Jun-04

Description : Gulf Power Plant Crist Unit 7

PCT-SB Run 3

Laboratory ID Number : AI16491

Test Name	Reference	Result	Units
Dry Basis			
Ash, Dry	ASTM D 5142	5.50	% By Weight
Heat of Combustion, Dry	ASTM D 5865	13212	Btu/lb
Carbon, Dry Basis	ASTM D 5373	75.84	% By Weight
Hydrogen, Dry Basis	ASTM D 5373	4.84	% By Weight
Nitrogen, Dry Basis	ASTM D 5373	1.44	% By Weight
Oxygen, Dry Basis	ASTM D 3176	11.93	% By Weight
Carbon Fixed, Dry	ASTM D 3172	56.97	% By Weight
Volatiles, Dry Basis	ASTM D 5142	37.53	% By Weight
Sulfur, Dry Basis	ASTM D 4239	0.45	% By Weight
As Received			
Moisture, Total	ASTM D 2013	13.06	% By Weight
Ash, As Received	ASTM D 5142	4.78	% By Weight
Heat of Combustion, As Received	ASTM D 5865	11487	Btu/lb
Carbon, As Received	ASTM D 5373	65.94	% By Weight
Hydrogen, As Received	ASTM D 5373	4.21	% By Weight
Nitrogen, As Received	ASTM D 5373	1.25	% By Weight
Oxygen, As Received	ASTM D 3176	10.37	% By Weight
Carbon Fixed, As Received	ASTM D 3172	49.53	% By Weight
Volatiles, As Received	ASTM D 5142	32.63	% By Weight
Sulfur, As Received	ASTM D 4239	0.39	% By Weight
General			
Heat of Combustion, MAF	ASTM D 5865	13981	Btu/lb
Sulfur, lbs/mmBTU	ASTM D 3180	0.341	lbs/mmBTU

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments:

CC: John Dominey

Quality Control ____________________ **Supervision**____________________ Date : 7/2/2004

smk/coa

From: Fleming, William C.
Sent: Monday, June 14, 2004 6:53 PM
To: Howton, Charles T.;,Daniels, Mel W.; Cotton, Ronald G.; Dominey, John M.; Beaty, Kevin L.; Stanton, John T.
Cc: O'Mary, Arthur L.
Subject: June 14 LOI
The middle hopper results are from a composite sample taken from all hoppers in the next row back from the front row. These hoppers lacked enough ash to make a sample from each hopper.

CRIST PLANT LOI WORKSHEET

DATE = 6/14/2004

Unit 7 LOI's
Special testing

HOPPER	CRUCIBLE NUMBER	CRUCIBLE WEIGHT	CRUCIBLE AND SAMPLE WEIGHT	POST FURNACE WEIGHT	LOI
7A2 Front	10	14.9623	15.9680	15.9150	5.27
7A2 Front	71	13.8768	15.1223	15.0440	6.29
7A3Front	90	14.0090	15.1755	15.1017	6.33
7A3Front	2	16.8588	17.9751	17.9038	6.39
7A Middle	84	15.0015	16.0497	15.9210	12.28
7A Middle	14	17.2266	18.2300	18.1109	11.87
7B3 Front	73	14.1905	15.4500	15.4149	2.79
7B3 Front	8	14.2126	15.6749	15.6320	2.93
7B4 Front	24	14.5600	15.7085	15.6808	2.41
7B4 Front	12	14.0774	15.1569	15.1274	2.73
7B Middle	17	14.1059	15.6981	15.5655	8.33
7B Middle	55	14.5705	15.9199	15.8087	8.24

From: McKinney, Jeff
Sent: Friday, June 18, 2004 4:01 PM
To: Dominey, John M.; Beaty, Kevin L.
Cc: O'Mary, Arthur L.
Subject: June 14 LOI
The middle hopper results are from a composite sample taken from all hoppers in the next row back from the front row. These hoppers lacked enough ash to make a sample from each hopper.

CRIST PLANT LOI WORKSHEET

DATE = 6/14/2004

Unit 7 LOI's
Special testing

HOPPER	CRUCIBLE NUMBER	CRUCIBLE WEIGHT	CRUCIBLE AND SAMPLE WEIGHT	POST FURNACE WEIGHT	LOI
7A4-3	37	15.1349	16.3612	16.3008	4.93
7A4-3	81	15.033	16.2467	16.1925	4.47
7A4-4	5	15.486	16.5945	16.5404	4.88
7A4-4	18	14.3758	15.4263	15.3769	4.70
7B4-3	44	15.0928	15.9567	15.8855	8.24
7B4-3	13	14.744	15.844	15.755	8.09
7B4-4	70	14.9409	15.8236	15.7303	10.57
7B4-4	4	15.1493	16.159	16.0511	10.69

General Test Laboratory
P.O. Box 2641
Birmingham, Alabama 35291
(205) 664 - 6081

CERTIFICATE OF ANALYSIS

TO: Kevin Beaty
Gulf Power Co.

Customer Account : CRI07SP
Sample Date : 14-Jun-04
Laboratory Account : CRI07SP
Received Date : 16-Jun-04

Description : Gulf Power Plant Crist Unit 7

PCT-SB Run 1

Laboratory ID Number : AI16489

Test Name	Reference	Result	Units
Dry Basis			
Ash, Dry	ASTM D 5142	4.95	% By Weight
Heat of Combustion, Dry	ASTM D 5865	13300	Btu/lb
Carbon, Dry Basis	ASTM D 5373	76.40	% By Weight
Hydrogen, Dry Basis	ASTM D 5373	4.88	% By Weight
Nitrogen, Dry Basis	ASTM D 5373	1.45	% By Weight
Oxygen, Dry Basis	ASTM D 3176	11.87	% By Weight
Carbon Fixed, Dry	ASTM D 3172	57.67	% By Weight
Volatiles, Dry Basis	ASTM D 5142	37.38	% By Weight
Sulfur, Dry Basis	ASTM D 4239	0.45	% By Weight
As Received			
Moisture, Total	ASTM D 2013	12.87	% By Weight
Ash, As Received	ASTM D 5142	4.31	% By Weight
Heat of Combustion, As Received	ASTM D 5865	11588	Btu/lb
Carbon, As Received	ASTM D 5373	66.57	% By Weight
Hydrogen, As Received	ASTM D 5373	4.25	% By Weight
Nitrogen, As Received	ASTM D 5373	1.26	% By Weight
Oxygen, As Received	ASTM D 3176	10.34	% By Weight
Carbon Fixed, As Received	ASTM D 3172	50.25	% By Weight
Volatiles, As Received	ASTM D 5142	32.57	% By Weight
Sulfur, As Received	ASTM D 4239	0.39	% By Weight
General			
Heat of Combustion, MAF	ASTM D 5865	13993	Btu/lb
Sulfur, lbs/mmBTU	ASTM D 3180	0.338	lbs/mmBTU

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments:

CC: John Dominey

Quality Control ____________________ **Supervision**________________________ Date : 7/2/2004

smk/coa

General Test Laboratory
P.O. Box 2641
Birmingham, Alabama 35291
(205) 664 - 6081

CERTIFICATE OF ANALYSIS

TO: Kevin Beaty
Gulf Power Co.

Customer Account : CRI07SP
Sample Date : 14-Jun-04
Laboratory Account : CRI07SP
Received Date : 16-Jun-04

Description : Gulf Power Plant Crist Unit 7

PCT-SB Run 2

Laboratory ID Number : AI16490

Test Name	Reference	Result	Units
Dry Basis			
Ash, Dry	ASTM D 5142	5.09	% By Weight
Heat of Combustion, Dry	ASTM D 5865	13307	Btu/lb
Carbon, Dry Basis	ASTM D 5373	75.98	% By Weight
Hydrogen, Dry Basis	ASTM D 5373	4.94	% By Weight
Nitrogen, Dry Basis	ASTM D 5373	1.45	% By Weight
Oxygen, Dry Basis	ASTM D 3176	12.08	% By Weight
Carbon Fixed, Dry	ASTM D 3172	57.46	% By Weight
Volatiles, Dry Basis	ASTM D 5142	37.45	% By Weight
Sulfur, Dry Basis	ASTM D 4239	0.46	% By Weight
As Received			
Moisture, Total	ASTM D 2013	12.60	% By Weight
Ash, As Received	ASTM D 5142	4.45	% By Weight
Heat of Combustion, As Received	ASTM D 5865	11630	Btu/lb
Carbon, As Received	ASTM D 5373	66.41	% By Weight
Hydrogen, As Received	ASTM D 5373	4.32	% By Weight
Nitrogen, As Received	ASTM D 5373	1.27	% By Weight
Oxygen, As Received	ASTM D 3176	10.56	% By Weight
Carbon Fixed, As Received	ASTM D 3172	50.22	% By Weight
Volatiles, As Received	ASTM D 5142	32.73	% By Weight
Sulfur, As Received	ASTM D 4239	0.40	% By Weight
General			
Heat of Combustion, MAF	ASTM D 5865	14021	Btu/lb
Sulfur, lbs/mmBTU	ASTM D 3180	0.346	lbs/mmBTU

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments:

CC: John Dominey

Quality Control ____________________ **Supervision** ____________________ **Date :** 7/2/2004

smk/coa

General Test Laboratory
P.O. Box 2641
Birmingham, Alabama 35291
(205) 664 - 6081

CERTIFICATE OF ANALYSIS

TO: Kevin Beaty
Gulf Power Co.

Customer Account : CRI07SP
Sample Date : 14-Jun-04

Laboratory Account : CRI07SP
Received Date : 16-Jun-04

Description : Gulf Power Plant Crist Unit 7

PCT-SB Run 3

Laboratory ID Number : AI16491

Test Name	Reference	Result	Units
Dry Basis			
Ash, Dry	ASTM D 5142	5.50	% By Weight
Heat of Combustion, Dry	ASTM D 5865	13212	Btu/lb
Carbon, Dry Basis	ASTM D 5373	75.84	% By Weight
Hydrogen, Dry Basis	ASTM D 5373	4.84	% By Weight
Nitrogen, Dry Basis	ASTM D 5373	1.44	% By Weight
Oxygen, Dry Basis	ASTM D 3176	11.93	% By Weight
Carbon Fixed, Dry	ASTM D 3172	56.97	% By Weight
Volatiles, Dry Basis	ASTM D 5142	37.53	% By Weight
Sulfur, Dry Basis	ASTM D 4239	0.45	% By Weight
As Received			
Moisture, Total	ASTM D 2013	13.06	% By Weight
Ash, As Received	ASTM D 5142	4.78	% By Weight
Heat of Combustion, As Received	ASTM D 5865	11487	Btu/lb
Carbon, As Received	ASTM D 5373	65.94	% By Weight
Hydrogen, As Received	ASTM D 5373	4.21	% By Weight
Nitrogen, As Received	ASTM D 5373	1.25	% By Weight
Oxygen, As Received	ASTM D 3176	10.37	% By Weight
Carbon Fixed, As Received	ASTM D 3172	49.53	% By Weight
Volatiles, As Received	ASTM D 5142	32.63	% By Weight
Sulfur, As Received	ASTM D 4239	0.39	% By Weight
General			
Heat of Combustion, MAF	ASTM D 5865	13981	Btu/lb
Sulfur, lbs/mmBTU	ASTM D 3180	0.341	lbs/mmBTU

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments:

CC: John Dominey

Quality Control ______________________ **Supervision**________________________ Date : 7/2/2004

smk/coa

Plant Crist

Unit	Condition	Run #	Date of Run	Start-time	End-time	Number of Opacity data points	Actual Opacity Observations (%)												Average Opacity [%]	Maximum Opacity [%]	Particulate emission rate (lbs / MMBtu)
Unit 6	-	1	3/25/2003	7:48	8:52	12	7.4	7.5	7.4	7.4	7.3	7.3	7.3	7.3	7.3	7.4	7.3	7.3	7.4	7.5	0.00401
Unit 6	-	2	3/25/2003	9:04	10:08	11	7.2	7.2	7.3	7.2	7.2	7.2	7.1	7.1	7.1	7.2	7.1	-	7.2	7.3	0.00474
Unit 6	-	3	3/25/2003	10:19	11:25	12	7.1	7	7.1	7.2	7.2	7.2	7.2	7.1	7.1	7.2	7.1	7.2	7.1	7.2	0.00371
Unit 6	1	1	3/26/2003	7:40	8:44	10	31.2	23.8	24	24.7	23.6	23.3	23.3	30.2	23.8	24	-	-	25.2	31.2	0.0401
Unit 6	1	2	3/26/2003	9:48	10:52	12	26.8	26.6	26.3	26.4	27	27.8	26.9	27.1	26.3	34.9	27.1	26.3	27.5	34.9	0.0378
Unit 6	1	3	3/26/2003	11:03	12:07	11	26.1	26.6	25.9	32.5	26.8	26.1	28.9	26.4	26.5	26.4	26.5	-	27.2	32.5	0.0383
Unit 6	2	1	3/27/2003	8:10	9:14	10	31.8	29.9	31.4	30.7	36.1	35.2	30.4	34.8	30.7	30.2	-	-	32.1	36.1	0.0553
Unit 6	2	2	3/27/2003	10:13	11:17	11	32.2	33.3	33.6	30.7	31.5	31.1	36.8	35.6	31.7	36.9	30.4	-	33.1	36.9	0.0618
Unit 6	2	3	3/27/2003	11:26	12:23	10	30.5	30.7	41	31.3	36.6	30.8	30.8	30.8	31	42.1	-	-	33.6	42.1	0.0639
Unit 7	1	1	6/17/2004	13:58	15:04	10	21.1	17.4	17.6	17.8	18.2	17.4	17.6	17.7	22.2	18.6	-	-	18.6	22.2	0.0518
Unit 7	1	2	6/17/2004	16:32	17:40	12	17.4	17.1	17.3	17.3	17.1	23.2	19.2	17.5	17.5	17.6	17.8	18.4	18.1	23.2	0.0631
Unit 7	1	3	6/17/2004	17:52	18:58	11	24.9	18.2	17.9	18	18.5	18.6	19.1	21.1	18.8	18.5	18.7	-	19.3	24.9	0.0414

Holtom, Jonathan

From: Huey.Joel@epamail.epa.gov
Sent: Friday, October 08, 2004 5:26 PM
To: Holtom, Jonathan
Subject: Fw: Utility CAM submittal

FYI, this was my response to Peter, which he did not respond back to (which I interpret to mean he's in a agreement--he'd say something if he disagreed). Please don't distribute this email though. Thanks. Joel

----- Forwarded by Joel Huey/R4/USEPA/US on 10/08/2004 05:23 PM -----

Joel Huey/R4/USEPA/US
09/23/2004 06:12 PM

To
Peter Westlin/RTP/USEPA/US

cc
Barrett Parker/RTP/USEPA/US@EPA, Brandi Johnson/R4/USEPA/US@EPA, Dave McNeal/R4/USEPA/US@EPA, ksschaffner@rti.org, rmneulicht@rti.org, Gregg Worley/R4/USEPA/US@EPA

Subject
Re: Utility CAM submittal(Document link: Joel Huey)

Peter,
Thanks for the additional comments. These units are only subject to a 40% opacity limit. They're old units, so apparently not subject to NSPS. For fossil fuel generators, Florida's rules have a 20% opacity limit that can be raised to 40% if they conduct quarterly PM tests (which can be reduced to annual if approved by the State). Certainly, there are incentives for facilities to keep opacity levels below whatever the applicable limit is--citizens groups keep a keen eye on opacity data because it's easy to use and often shows violations.

Your comments are helpful, and I'm glad we're having this exchange relatively early (not many utilities with CAM in their permits yet) because a fundamental question is raised as to whether we should be reviewing CAM submittals to assure compliance with emission limits or to assure proper O&M of control equipment. I know proper O&M is our goal, but basing indicator ranges on that would require a much more involved review that we had anticipated. Also, we have to implement the rules as they are written and must back up our comments to state agencies with citations to rule requirements. And while I don't disagree with the rationale behind the comments you have forwarded, they seem to go beyond what we can require.

Regarding historical data, we realize the Crist submittal contains none. Part 64 requires that CAM submittals include test data: “The owner or operator shall submit control device (and process and capture system, if
applicable) operating parameter data obtained during the conduct of the applicable compliance or performance test conducted under conditions specified by the applicable rule.” [64.4(c)(1)] However, the rule does not appear to require historical data, saying only that "The owner or operator also shall submit any data supporting the justification . . ." [64.4(b)] So, a facility does not have to submit historical data if none exists or if they believe their test data alone adequately supports their justification. The EPRI protocol does mention typical opacity of 5% and PM emissions of 0.03 lb/mmbtu, but I see no historical data there.

Regarding the excursion levels, the second sentence of 64.3(a)(2) does say that "Such range(s) or condition(s) shall reflect the proper operation and maintenance of the control device (and associated capture system), in accordance with applicable design properties, for minimizing emissions over the anticipated range of operating conditions . . ." I initially felt this might give us a basis for a lower opacity indicator, but, as you have pointed out, such language is similar to general requirements to minimize emissions that have proven difficult to enforce. Also, the last phrase of this sentence weakens the position by allowing that the range shall be "at least to the level required to achieve compliance with the applicable requirements."

Setting a lower opacity as the excursion level, such as 10% or 20% (without use of the model), would likely result in a larger number of excursions than 27%. This would be undesirable because part 70 requires each excursion to be reported as a "possible exception to compliance," which, at 20%, they probably are not. (Companies consider excursions more than a nuisance. They avoid them like the plague because of damage they believe is caused to their public image and data citizens will use to sue for what they perceive as noncompliance.)

So the options appear to be:
1. As in the EPRI protocol, use 20% opacity as a trigger to run the model. The model would result in a more appropriate number of excursions than just using 20% opacity alone. (I don't know why Crist chose not to go this route.) 2. As Crist has done, use opacity alone as an indicator and use an appropriate and reasonable range. It appears to us that 27% provides a reasonable assurance that the source is complying with the PM limit.

We'll provide your comments for consideration by the State, but it doesn't appear that we have a strong position for requiring a lower excursion range. Of course, we would be happy to discuss this with you further and consider any additional comments you may have. Thanks. Joel

Peter
Westlin/R
TP/USEPA/
US

To
Joel Huey/R4/USEPA/US@EPA

cc
Brandi Johnson/R4/USEPA/US@EPA, Dave McNeal/R4/USEPA/US@EPA, Barrett Parker/RTP/USEPA/US@EPA, rmneulicht@rti.org, ksschaffner@rti.org

09/22/2004 06:55 AM

Subject
Utility CAM submittal

Joel:

I received some comments on the reply I sent to you that are worth sharing. One factor I mentioned but did not dwell on was that there remains a 20 percent opacity limit (6-minute average) and that the source owner must report excess opacity emissions for every 6-minute average over 20 percent (except for exempt periods). Given the incentive to keep the opacity levels below 20 percent (even with a 2 percent or 5 percent allowance), I think that the number of excursions above the 27 percent opacity indicator range for demonstrating compliance with the PM limit will be mitigated. That is, I think that the combination of the two indicators, opacity and CAM PM, using the same COMS data will work in favor of PM control below the level measured during the performance test at the PM emissions limit level (~0.09 lb/MMBtu). At least, I hope there is an incentive to keep the opacity levels below 20 percent - that the state intends to enforce that limit, too. Even so, the comments below are certainly relevant and should be considered in a response to the source or other facility who proposes this approach with or without the margin of safety provided by a lower
opacity limit. The additional comments are:

1. It seems the plan, or at least the rationale for selection of the indicator range, is missing one very important factor. What do the historical data show? When the process and APCD are operating properly and the APCD is properly maintained, what are the emissions and the opacity? The indicator should be set somewhere between this level and the

maximum demonstrated to show a reasonable assurance of compliance. In this case, the facility has conducted a test (3 runs) at the maximum PM limit with the APCD at less than optimum conditions, and they have selected an indictor range with essentially no margin of compliance. Recognizing the purpose of CAM is not to change the emission limit and restrict operations, nonetheless, the facility has an obligation to maintain and operate the APCD following good practices. We have all heard horror stories of facilities that have operated their control devices during a performance test at optimum conditions that cannot be maintained during normal operations and then been stuck with operating limits they cannot achieve; I see this as the opposite scenario. The facility has pushed the APCD limit to the worst operating conditions still showing compliance and they want to (or would be able to without an excursion) operate at that level all the time. So what do the historical data indicate the facility is capable of achieving when the equipment is operating properly and the process is at full load? The indicator should be set somewhere between this level and the maximum.

If they want to push it to the max, I do not think 3 test runs at each of three operating levels are sufficient data to develop the correlation. The PM CEMS PS-11, for example, requires a minimum of 15 test runs. The EPRI CAM example had nine test runs to establish the correlation for the ESP model.

Note, as a means of reference, that in the EPRI example CAM plan:

1) the emission limit is 3.4 lb/MMBtu,

2) "at full power when the ESP is fully operational, PM emissions typically are less than 0.03 lb/mmbtu and have less than 5% opacity,"

3) the opacity indicator (which would trigger running the ESP model) was set at 20% opacity which correlated with a PM level of approximately .18 lb/mmbtu or 75% of the PM emission limit, and

4) the ESP model output (the excursion indicator) was set at 90% of the emission limit.

So, in the EPRI case, the facility has quite a bit of wiggle room above "normal" operations, but is still well below the emission limit when action is triggered. This is not the case for the Crist proposed plan.

2. The EPRI consultant claims opacity is not that great an indicator of PM; they claim the Computer model is a better indicator (more robust) because it takes many ESP performance factors into account. That said, the "correlation" for the three runs presented in this plan looks really good......but it is only three runs. I guess if opacity monitors are this good, why are people interested in PM CEMS? That said, this simply leads me back to item 1, above....more margin, and or more data, and show me the historical data.

3. I agree with Jonathan that this approach is less stringent than what they had before. Before, if more than 5% of the COMS readings were greater than 20%, they had to do a performance test. Looking at the correlation they have submitted, 20% opacity correlates to 0.5 lb/mmbtu or 50% of the emission limit. Consequently, there currently is an incentive for them to operate at less than 50% of the standard 95% of the time.

With the new indicator, even if 27% opacity is selected (rather than the 30% the facility is proposing, they can operate at 90% of the emission limit 100% of the time with no corrective action. Legally, I guess they have a right to do this, but in the spirit of CAM if they are capable of operating at, let's say for arguments sake, 10% of the emission limit when the APCD is well maintained, the indicator range should be set lower than they are requesting.

I wonder how big a disincentive conducting a Performance test really is, other than economic. I am sure if they have to conduct a test, they will tune up that ESP before they do the test to assure they show compliance. So in a way I guess the requirement to conduct a test does serve the intended purpose; they make sure the ESP is properly operating....at least once a quarter...but then what? What is the facilities history here? Have they been conducting tests regularly? If not, this tells me they can operate below 20% opacity most of the time.

This brings up a point. Perhaps the facility is concerned that if they select a lower indicator range such as 20 percent, they will have a sufficient number of excursions to trigger reporting and corrective actions under "normal operating conditions;" e.g., let's say under normal operating conditions they operate at 20 to 25% opacity 3% of the time. Under the current permit conditions this would not trigger a performance test. If they set the CAM trigger at 20%, they would be reporting excursions (and needing to take corrective action) 3% of the time even though the correlation would indicate they are operating at less than 80% of the PM emission limit at a 25% opacity level.

One could consider something like defining an excursion when the opacity exceeds more than 20% for x percent of the time in a 24 hour period, or more than 4 contiguous 3 hour averages, but this starts to get complicated. I think this leads back to item No. 1 above; i.e., looking at historical data to see if one can find the happy medium between a level that does not result in "nuisance" excursions and a level that provides a reasonable assurance of compliance.

If they really do not want to be bothered with "excursions" at a lower emissions level with more margin of error, I would say they need collect more data to show that the correlation is "robust," and as you indicated get a statistician involved.

I hope that these are helpful,

Peter

Holtom, Jonathan

From:	Huey.Joel@epamail.epa.gov
Sent:	Friday, October 08, 2004 5:24 PM
To:	Holtom, Jonathan
Subject:	Fw: Utility CAM submittal

Jonathan,
I had promised to send you additional comments on Crist. I really wanted to discuss them with Peter some more and send you a condensed version, but I just haven't had time. Now I'm on a detail to Region 4's Waste Division till January 24. Please see the comments below and let me know if you have any questions. Joel

----- Forwarded by Joel Huey/R4/USEPA/US on 10/08/2004 05:19 PM -----

Peter
Westlin/RTP/
USEPA/US To
Joel Huey/R4/USEPA/US@EPA
09/22/2004 cc
06:55 AM Brandi Johnson/R4/USEPA/US@EPA, Dave
McNeal/R4/USEPA/US@EPA, Barrett
Parker/RTP/USEPA/US@EPA,
rmneulicht@rti.org,
ksschaffner@rti.org
Subject
Utility CAM submittal

Joel:

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1. It seems the plan, or at least the rationale for selection of the indicator range, is missing one very important factor. What do the historical data show? When the process and APCD are operating properly and the APCD is properly maintained, what are the emissions and the opacity? The indicator should be set somewhere between this level and the maximum demonstrated to show a reasonable assurance of compliance. In this case, the facility has conducted a test (3 runs) at the maximum PM limit with the APCD at less than optimum conditions, and they have selected an indictor range with essentially no margin of compliance. Recognizing the purpose of CAM is not to change the emission limit and restrict operations, nonetheless, the facility has an obligation to maintain and operate the APCD following good practices. We have all heard horror stories of facilities that have operated their control devices during a performance test at optimum conditions that cannot be maintained during normal operations and then been stuck with operating limits they cannot achieve; I see this as the opposite scenario. The facility has pushed the APCD limit to the worst operating conditions still showing compliance and they want to (or would be able to without an excursion) operate at that level all the time. So what do the historical data indicate the facility is capable of achieving when the equipment is operating properly and the process is at full load? The indicator should be set somewhere between this level and the maximum.

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One could consider something like defining an excursion when the opacity exceeds more than 20% for x percent of the time in a 24 hour period, or more than 4 contiguous

3 hour averages, but this starts to get complicated. I think this leads back to item No. 1 above; i.e., looking at historical data to see if one can find the happy medium between a level that does not result in "nuisance" excursions and a level that provides a reasonable assurance of compliance.

If they really do not want to be bothered with "excursions" at a lower emissions level with more margin of error, I would say they need collect more data to show that the correlation is "robust," and as you indicated get a statistician involved.

I hope that these are helpful,

Peter

Emissions Unit -004

1,096.7 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 1. MONITORING APPROACH FOR UNIT -004

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in the ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 27%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. Note: Based on data submitted by the applicant, an exceedance of the PM limit will likely occur if the opacity is greater than 30% for 3 hours.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	E. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data.
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -005

1,096.7 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 2. MONITORING APPROACH FOR UNIT -005

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in the ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 28%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. Note: Based on data submitted by the applicant, an exceedance of the PM limit will likely occur if the opacity is greater than 31% for 3 hours.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	F. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data.
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -006

3,704.8 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 3. MONITORING APPROACH FOR UNIT -006

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 1-hour opacity average greater than 33%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. Note: Based on data submitted by the applicant, an exceedance of the PM limit will likely occur if the opacity is greater than 37% for 3 hours.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	G. Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data.
	F. Averaging Period	The 6-minute opacity data is used to calculate 1-hour averages.

Emissions Unit -007

6,406.4 MMBtu/Hr Coal, Gas and Oil-Fired Boiler
Particulate Matter Emissions Controlled By An ESP

Monitoring Approach

TABLE 4. MONITORING APPROACH FOR UNIT -007

		Compliance Indicator
I.	Indicator	Opacity of ESP exhaust.
	Measurement Approach	COMS in ESP outlet duct.
II.	Indicator Range	An excursion is defined as any 6-minute opacity average greater than 18%. Excursions trigger an inspection, any corrective action necessary to lower the opacity, and a documentation of the event. An exceedance of the Opacity limit occurs if the opacity is greater than 20% for any 6-minute average. An exceedance of the opacity limit will most likely occur before the PM limit is reached.
III.	Performance Criteria	
	A. Data Representativeness	The COMS were installed at representative locations in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
	B. Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
	C. QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
	D. Monitoring Frequency	The opacity of the cold-side ESP outlet duct is monitored continuously.
	H. Data Collection Procedures	The DAS retains all 6-minute average opacity data.
	F. Averaging Period	6-minute averages.

Cedar Bay Generating Company, L.P.

Emissions Units 001, 002 & 003

1,063 MMBtu/Hr Coal And Petroleum Coke-Fired Circulating Fluidized Bed Boilers
Particulate Matter Emissions Controlled By Baghouses

Monitoring Approach and Corrective Action Procedures

Table 1. Monitoring Approach

	Compliance Indicator
I. Indicator	Duct opacity.
Measurement Approach	Continuous opacity monitoring system (COMS).
II. Indicator Range	An excursion is defined as 5 consecutive 6-minute averages of opacity greater than 10.0% (other than startup and shutdown periods).
III. Performance Criteria	
A. Data Representativeness	Based on available data under normal operation, the representative stack opacity of each unit is in the range of 3 to 7%. A 50% average opacity above 7% during non-startup or shutdown periods is atypical and may indicate a potential problem with the baghouse.
B. Verification of Operational Status	Annual testing during normal operation is used to verify particulate mass loading. The COM system is audited quarterly.
C. QA/QC Practices and Criteria	Install and operate COMS according to 40 CFR Part 60 Appendix B, Performance Specification 1 and general provisions 60.13.
D. Monitoring Frequency	Continuous.
E. Data Collection Procedures	The COMS collects data that are reduced to 6-minute averages. Consecutive 6-minute averages are tracked through the Distributed Control System (DCS) and CEM software.
F. Averaging Period	Five consecutive 6-minute averages.

Gulf Power Proposed CAM Limits

10/19/2004

Unit	Particulate Limit	Gulf Proposed CAM Excursion/Exceedance	**FDEP Proposed CAM** Excursion/Exceedance
Crist 7	.1 lb/mmbtu	18%/20% (3/3 hour)	18%/20% (6/6 min)
Crist 6	.1 lb/mmbtu	33%/37% (3/3 hour)	33%/37% (1/3 hour)
Crist 5	.1 lb/mmbtu	28%/31% (3/3 hour)	28%/31% (1/3 hour)
Crist 4	.1 lb/mmbtu	27%/30% (3/3 hour)	27%/30% (1/3 hour)
Smith 1	.1 lb/mmbtu	32%/36% (3/3 hour)	30%/34% (1/3 hour)
Smith 2	.1 lb/mmbtu	24%/27% (3/3 hour)	24%/27% (1/3 hour)
Scholz 1	.1 lb/mmbtu	14%/16% (3/3 hour)	14%/16% (1/3 hour)
Scholz 2	.1 lb/mmbtu	11%/13% (3/3 hour)	11%/13% (1/3 hour)

UNITED STATES ENVII.ONMENTAL PROTECTION AGENCY
AIR, PESTICIDES & TOXICS MANAGEMENT DIVISION
Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303
Fax Number: (404)562-9164

FACSIMILE TRANSMISSION SHEET

DATE: October 25, 2004	NUMBER OF PAGES (including this sheet): 18
TO: Greg Deangelo	PHONE: (850)921-9506
ADDRESS:	FAX NUMBER: (850)922-6979
FROM: Jason Dressler	PHONE: (404)562-9208

Please call me if this transmission is received poorly.

SPECIAL INSTRUCTIONS: Gulf/Southern NOV - 1999

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4

IN THE MATTER OF:	)	
	)	
Southern Company Services, Inc.,Georgia Power Company, Alabama Power Company, Mississippi Power Company, Gulf Power Company, and Savannah Electric & Power Company	)	Notice of Violation EPA-CAA-2000-04-0006
	)	
Proceedings Pursuant to Section 113(a)(1) of the Clean Air Act, 42 U.S.C. §7413(a)(1)	)	
	)	

NOTICE OF VIOLATION

This Notice of Violation ("NOV") is issued to Southern Company Services, Inc. (Southern), Georgia Power Company, Alabama Power Company, Mississippi Power Company, Gulf Power Company, and Savannah Electric & Power Company (hereinafter referred to collectively as the "Southern Companies") for violations of the Clean Air Act ("the Act") at the coal-fired power plants identified below. The Southern Companies have embarked on a program of modifications intended to extend the useful life, regain lost generating capacity, and/or increase capacity at their coal-fired power plants.

Commencing at various times from 1977 to the present, the Southern Companies have modified and operated the coal-fired power plants identified below without obtaining New Source Review ("NSR") permits authorizing the construction and operation of physical modifications at their boiler units as required by the Act. In addition, for each physical modification at these power plants, the Southern Companies have operated these modifications without installing pollution control equipment required by the Act. These violations of the Act and the State Implementation Plans ("SIP") of Georgia, Alabama, Mississippi and Florida have resulted in the release of massive amounts of Sulfur Dioxide ("SO_2"), Nitrogen Oxides ("NO_x"), and Particulate Matter ("PM") into the environment. Until these violations are corrected, the Southern Companies will continue to release massive amounts of illegal SO_2, NOx, and PM into the environment.

This NOV is issued pursuant to Section 113(a)(1) of the Act, as amended, 42 U.S.C.A. Section 7401-7671q. Section 113(a) of the Act requires the Administrator of the United States Environmental Protection Agency ("EPA") to notify any person in violation of a state implementation plan or permit of the violations. The authority to issue this NOV has been delegated to the

Regional Administrator of EPA Region 4 and further redelegated to the Director, Air, Pesticides and Toxics Management Division, EPA, Region 4.

STATUTORY AND REGULATORY BACKGROUND

1. When the Act was passed in 1970, Congress exempted existing facilities, including the coal-fired power plants that are the subject of this Notice, from many of its requirements. However, Congress also made it quite clear that this exemption would not last forever. As the United States Court of Appeals for the D.C. Circuit explained in Alabama Power v. Costle, 636 F.2d 323 (D.C. Cir. 1979), "the statutory scheme intends to 'grandfather' existing industries; but...this is not to constitute a perpetual immunity from all standards under the PSD program." Rather, the Act requires grandfathered facilities to install modern pollution control devices whenever the unit is proposed to be modified in such a way that its emissions may increase.

2. The NSR provisions of Parts C and D of Title I of the Act require preconstruction review and permitting for modifications of stationary sources. Pursuant to applicable regulations, if a major stationary source is planning upon making a major modification, then that source must obtain either a PSD permit or a nonattainment NSR permit, depending on whether the source is located in an attainment or a nonattainment area for the pollutant being increased above the significance level. To obtain this permit, the source must agree to put on the best available control technology ("BACT") for an attainment pollutant or achieve the lowest achievable emission rate ("LAER") in a nonattainment area, or in the case of a modification that is not major, must meet the emission limit called for under the applicable minor NSR program.

3. Pursuant to the Act, the SIP of Georgia requires that no construction or operation of a modification of a major stationary source occur without first obtaining a NSR permit. See: for PSD permits in attainment areas, 40 C.F.R. § 52.21(i), and Section 7 of Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02, which is part of the Georgia SIP that was approved by EPA on September 18, 1979, as amended on February 10, 1982 (47 Fed. Reg. 6017), December 14, 1992 (57 Fed. Reg. 58989) and February 2, 1996 (61 Fed. Reg. 3817); for NSR permits in nonattainment areas, Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.03, which is part of the Georgia SIP that was approved by EPA on September 18, 1979 (44 Fed. Reg. 54047) and amended on March 8, 1995 (60 Fed. Reg. 12688); for minor modifications regardless of attainment status, Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.03, which is part of the Georgia SIP that was approved by EPA on August 20, 1976 (41 Fed. Reg. 35184), and amended on September 18, 1979 (44 Fed. Reg. 54047) and on March 8, 1995 (60 Fed. Reg. 12688).

Best Available Copy

4. Pursuant to the Act, the SIP of Alabama requires that no construction or operation of a modification of a major stationary source occur without first obtaining a permit. See: for PSD permits in attainment areas, 40 C.F.R. § 52.21(i), and Alabama Department of Environmental Management Code 335-3-14-.04(8), which is part of the Alabama SIP that was approved by EPA on March 9, 1983 (48 Fed. Reg. 9860); for NSR permits in nonattainment areas, Alabama Department of Environmental Management Code 335-3-14-.05, which is part of the Alabama SIP that was approved by EPA on November 10, 1981 (46 Fed. Reg. 55518), as amended on December 28, 1987 (52 Fed. Reg. 48812); and for minor modifications regardless of attainment status, Alabama Department of Environmental Management Code 335-3-14-.01, which is part of the Alabama SIP that was approved by EPA on November 10, 1981 (46 Fed. Reg. 55518), as amended on December 28, 1987 (52 Fed. Reg. 48812).

5. Pursuant to the Act, the SIP of Mississippi requires that no construction or operation of a modification of a major stationary source occur without first obtaining a permit. See: for PSD permits in attainment areas, 40 C.F.R. § 52.21(i), and Mississippi Commission on Natural Resources regulation APC-S-5, which is part of the Mississippi SIP that was approved by EPA on October 15, 1990 (55 Fed. Reg. 41692), and amended on June 14, 1992 (57 Fed. Reg. 34252), on May 5, 1995 (60 Fed. Reg. 22287), and July 15, 1997 (62 Fed. Reg. 37724); for NSR permits in nonattainment areas, Mississippi Commission on Natural Resources regulation APC-S-2, Section IV, which is part of the Mississippi SIP that was approved by EPA on February 4, 1972 (37 Fed. Reg. 10875), as amended on September 15, 1994 (59 Fed. Reg. 47258) and on May 2, 1995 (60 Fed. Reg. 214·2); and for minor modifications regardless of attainment status, Mississippi Commission on Natural Resources regulation APC-S-2, Sections III and IV, which are part of the Mississippi SIP that was approved by EPA on February 4, 1972 (37 Fed. Reg. 10875), as amended on September 15, 1994 (59 Fed. Reg. 47258) and on May 2, 1995 (60 Fed. Reg. 214·2).

6. Pursuant to the Act, the SIP of Florida requires that no construction or operation of a modification of a major stationary source without first obtaining a permit. See: for PSD permits in attainment areas, 40 C.F.R. § 52.21(i), and the current Florida SIP Rule 62-212.400, Florida Administrative Code (F.A.C.), which is part of the Florida SIP that was approved by EPA on November 22, 1983 (48 Fed. Reg. 52716), and amended on October 20, 1994 (59 Fed. Reg. 52916), and on January 11, 1995 (60 Fed. Reg. 2688); for NSR permits in nonattainment areas, 40 C.F.R. § 52.24(a), and Florida SIP Rule 62-212.500, F.A.C., which was approved by EPA on November 22, 1983 (48 Fed. Reg. 52716), and amended on October 20, 1994 (59 Fed. Reg. 52916); and for minor NSR permits regardless of attainment status, 62-212.300, F.A.C., which is part of the Florida SIP that was approved by EPA on October 20, 1994 (59 Fed. Reg. 52916). No SIP-approval for PSD has been given to the State of Florida for power plants which are also subject to the Florida Power Plant Siting Act

EPA40RC001881

(PPSA). Rather, Florida has a fully delegated PSD program with respect to power plants subject to the PPSA. Florida implements this delegation under 40 C.F.R. Section 52.21, whose provisions are incorporated by reference into the Florida SIP pursuant to 40 C.F.R. Section 52.530.

7. The SIP provisions identified in paragraphs 3-7 above are all federally enforceable pursuant to Sections 110 and 113 of the Act.

FACTUAL BACKGROUND

8. The Southern Companies are owners and/or operators of the facilities that are the subject of this NOV

9. Southern and Georgia Power Company operate the Scherer Plant, a fossil fuel-fired electric utility steam generating plant located at 10986 Highway 87, Monroe County, Juliette, Georgia, 31046. The plant consists of 4 boiler units with up to 269 810,000 mmBTU annual heat input, and began operations in 1982.

10. Southern and Georgia Power Company operate the Bowen Plant, a fossil fuel-fired electric utility steam generating plant located at 317 Covered Bridge Road, Bartow County, Cartersville, Georgia, 30120. The plant consists of 4 boiler units with 207,281,000 mmBTU annual heat input in 1998, and began operations in 1972.

11. Southern and Savannah Power Company operate the Kraft Plant, a fossil fuel-fired electric utility steam generating plant located at P.O. Box 4068, Chatham County, Port Wentworth, Georgia, 31407. The plant consists of 4 boiler units, with 7,630,000 mmBTU annual heat input in 1997, and began operations in 19[illegible]2.

12. The Scherer, Bowen and Kraft Plants are located in areas that have the following attainment/nonattainment classifications from 1979 to the present:

For NO_2, the areas have been classified attainment or unclassifiable;
For SO_2, the areas have been classified attainment or unclassifiable;
For PM, the areas have been classified attainment or unclassifiable;
For Ozone, the areas have been classified attainment or unclassifiable.

13. Southern and Alabama Power Company operate the Gorgas Steam Plant, a fossil fuel-fired electric utility steam generating plant located at 460 Gorgas Road, Walker County, Parrish, Alabama, 35580. The plant consists

of 5 boiler units (Nos. 6-10) with 89,621,000 mmBTU annual heat input in 1997, and began operations in 1972.

14. Southern and Alabama Power Company operate the Greene County Plant, a fossil fuel-fired electric utility steam generating plant located at Highway 83 and County Road 18, Greene County, Forkland, Alabama, 36732. The plant consists of 2 boiler units with 34,249,000 mmBTU annual heat input in 1997, and began operations in 1966.

15. The Gorgas and Green County Plants are located in areas that have the following attainment/nonattainment classifications from 1980 to the present:

For NO_2, the areas have been classified attainment or unclassifiable;
For SO_2, the areas have been classified attainment or unclassifiable;
For PM, the areas have been classified attainment or unclassifiable.
For Ozone, the areas have been classified attainment or unclassifiable.

16. Southern and Alabama Power Company operate the Barry Steam Plant, a fossil fuel-fired electric utility steam generating plant located at P.O. Box 70, Mobile County, Bucks Alabama, 36512. The plant consists of 5 boiler units with 119,483,000 mmBTU annual heat input in 1997, and began operations in 1971.

17. The Barry Steam Plant is located in an area that has the following attainment/nonattainment classifications from 1980 to the present:

For SO_2 and NO_2, the area has been classified attainment or unclassifiable;
For, Ozone, the area has been classified nonattainment until June 12, 1987 and attainment since that time; and
For TSP, the area has been classified nonattainment until November 15, 1984, and attainment since that time.

18. Southern and Alabama Power Company operate the Gaston Steam Plant, a fossil fuel-fired electric utility steam generating plant located at P.O. Box 1127, Shelby County, Wilsonville, Alabama, 35186. The plant consists of 5 boiler units with 11,239,000 mmBTU annual heat input in 1997, and began operations in 197..

19. The Gaston Steam Plant is located in an area that has the following attainment/nonattainment classifications from 1980 to the present:

For NO_2, the area has been classified attainment or unclassifiable;

For SO_2, the area has been classified attainment or unclassifiable;
For PM, the area has been classified attainment or unclassifiable.
For Ozone, the area has been classified attainment

20. Southern and Alabama Power Company operate the Miller Plant, a fossil fuel-fired electric utility steam generating plant located at 42050 Porter Road, Jefferson County, Quinton, Alabama, 35130. The plant consists of 4 boiler units with ?04,211,519 mmBTU annual heat input in 1998, and began operations in 197?.

21. The Miller Plant is located in an area that has the following attainment/nonattainment classifications from 1980 to the present:

For NO_2, the area has been classified attainment or unclassifiable;
For SO_2, the area has been classified attainment or unclassifiable;
For PM, the area has been classified attainment or unclassifiable.
For Ozone, the area has been classified attainment or unclassifiable.

22. Southern and Mississippi Power Company operate the Watson Electric Generating Plant, a fossil fuel-fired electric utility steam generating plant located at P.O. Box 4079, Harrison County, Gulfport, Mississippi, 39502. The plant consists of 2 boiler units (Nos. 4-5) with 46,831,000 mmBTU annual heat input in 1997, and began operations in 1973.

23. The Watson Plant is located in an area that has the following attainment/nonattainment classifications from 1980 to the present:

For NO_2, the area has been classified attainment or unclassifiable;
For SO_2, the area has been classified attainment or unclassifiable;
For PM, the area has been classified attainment or unclassifiable.
For Ozone, the area has been classified attainment.

24. Southern and Gulf Power Company operate the Crist Plant, a fossil fuel-fired electric utility steam generating plant located at One Energy Place, Escambia County, Pensacola, Florida, 32520. The plant consists of 4 boiler units (Nos. 4-7) with 44,407,000 mmBTU annual heat input in 1997, and began operations in 197?.

25. The Crist Plant is located in an area that has the following attainment/nonattainment classifications from 1980 to the present:

For NO_2, the area has been classified attainment or unclassifiable;

For SO_2, the area has been classified attainment or unclassifiable;
For PM, the area has been classified attainment or unclassifiable.
For ozone, the area has been classified attainment.

26. Each of the plants identified in paragraphs 9 through 25 above emits or has the potential to emit at least 100 tons per year of NOx, SO_2 and/or PM and is a major stationary source under the Act.

VIOLATIONS

Georgia Power Plants

A. Scherer Plant

27. In 1979, the Southern and Georgia Power Company "commenced construction" as that term is defined in the 1974 EPA PSD regulations, 40 C.F.R. § 51.21((b), and the Georgia SIP, Section 7 of Georgia Department of Natural Resources Air Quality Control Rule Chapter 391-3-1-.02, on the Scherer Plant in Juliette, Georgia. Construction on Units 3 and 4 was not completed until 1987 and 1989, respectively.

28. For each of these new source constructions that occurred at the Scherer Plant, neither Southern nor Georgia Power obtained a PSD permit pursuant to Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7) nor a minor NSR permit pursuant to Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.03.

29. None of this new source construction falls within the exemptions found at 40 C.F.R. § 52.21(i), because neither Southern nor Georgia Power ever obtained a PSD permit under the 1974 EPA PSD regulations, and the work was not completed in a reasonable time.

30. Each of these new source constructions resulted in a net significant increase in emissions, as that term is defined in 40 C.F.R. § 52.21(b), and Section 7 of Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02, for NOx, SO_2 and/or PM from Units 3 and 4 of the Scherer Plant.

31. Therefore, Southern and Georgia Power violated and continue to violate the Georgia SIP by constructing and operating the Scherer Plant without the necessary permit required by EPA and the Georgia SIP.

32. Each of these violations exists from the date of start of construction of Units 3 and 4, respectively, until the time that the Southern Company and Georgia Power obtain the appropriate NSR permit and operate the necessary pollution control equipment to satisfy the Georgia SIP.

B. Bowen Plant

33. On numerous occasions between 1979 and the date of this Notice, Southern and Georgia Power have made "modifications" to the Bowen Plant as defined by the Georgia SIP, Section 7 of Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02. These modifications include the replacement and redesign of the economizer for Unit 2 in 1992.

34. For each of the modifications that occurred at the Bowen Plant, neither Southern nor Georgia Power obtained a PSD permit pursuant to Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7), nor a minor NSR permit pursuant to Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.03. In addition, for modifications after 1992, no information was provided to the permitting agency of actual emissions after the modification as required by Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7).

35. None of these modifications fall within the "routine maintenance, repair and replacement" exemption found at 40 C.F.R. § 52.21(b)(2)(iii)(a), or Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7). Each of these changes was an expensive capital expenditure performed infrequently at the plant that constituted the replacement and/or redesign of a boiler component with a long useful life. In each instance, the change was performed to increase capacity, regain lost capacity, and/or extend the life of the unit. In many instances, the original component was replaced with a component that was substantially redesigned in a manner that increased emissions. That the "routine maintenance, repair and replacement" exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld by the court of appeals in 1990. Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

36. None of these modifications fall within the "increase in hours of operation or in the production rate" exemption found at 40 C.F.R. § 52.21(b)(2)(iii)(f), or Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7). This exemption is limited to stand-alone increases in operating hours or production rates, not where such increases follow or are otherwise linked to construction activity. That the hours of operation/rates of production exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld twice by the court of appeals, in 1989 and

in 1990. Puerto Rican Cement Co v. EPA, 889 F.2D 292 (1st Cir. 1989); Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

37. None of these modifications fall within the "demand growth" exemption found at Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7), because for each modification a physical change was performed which resulted in the emissions increase.

38. Each of these modifications resulted in a net significant increase in emissions, as that term is defined at Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7) from the Bowen Plant for NOx, SO_2 and/or PM.

39. Therefore, Southern and Georgia Power violated and continue to violate the Georgia SIP by constructing and operating modifications at the Bowen Plant without the necessary permit required by the Georgia SIP.

40. Each of these violations exists from the date of start of construction of the modification until the time that Southern and Georgia Power obtain the appropriate NSR permit and operate the necessary pollution control equipment to satisfy the Georgia SIP.

Alabama Power Plants

C. Miller Plant

41. In 1979, Southern and Alabama Power "commenced construction" as that term is defined in the 1974 EPA PSD regulations, 40 C.F.R. § 51.21(b), and the Alabama SIP, ADEM Code 335-3-14-.04, on the Miller Plant in Quinton, Alabama. Construction on Units 3 and 4 was not completed until 1989 and 1991, respectively.

42. For each of the new source constructions that occurred at the Miller Plant, neither Southern nor Alabama Power obtained a PSD permit pursuant to ADEM Code 335-3-14-.04, a nonattainment NSR permit pursuant to ADEM Code 335-3-14-.05, nor a minor NSR permit pursuant to ADEM Code 335-3-14-.01.

43. None of this new source construction falls within the exemptions found at 40 C.F.R. § 52.21(i), because neither Southern nor Alabama Power ever obtained a PSD permit under the 1974 or 1978 EPA PSD regulations, and the work was not completed in a reasonable time.

44. Each of these new source constructions resulted in a net significant increase in emissions, as that term is defined in 40 C.F.R. § 52.21(b), and ADEM Code 335-3-14-.04(2), for NOx, SO_2 and/or PM from Units 3 and 4 of the Miller Plant.

45. Therefore, Southern and Alabama Power violated and continue to violate the Alabama SIP by constructing and operating the Miller Plant without the necessary permit required by EPA and the Alabama SIP.

46. Each of these violations exists from the date of start of construction of Units 3 and 4, respectively, until the time that Southern and Alabama Power obtain the appropriate NSR permit and operate the necessary pollution control equipment to satisfy the Alabama SIP.

D. Barry, Gorgas, Gaston and Greene County Plants

47. On numerous occasions between 1979 and the date of this Notice, Southern and Alabama Power have made "modifications" of the Barry Plant as defined by the Alabama SIP, Alabama Department of Environmental Management (ADEM) Code 335-3-14-.04(2)(b)(1). These modifications include the installation of a new economizer on Unit 5 in 1993.

48. For each of the modifications that occurred at the Barry Plant, neither Southern nor Alabama Power obtained a PSD permit pursuant to ADEM Code 335-3-14-.04, a nonattainment NSR permit pursuant to ADEM Code 335-3-14-.05, nor a minor NSR permit pursuant to ADEM Rule 335-3-14-.01. In addition, no information was provided to the permitting agency of actual emissions after a modification as required by ADEM Code 335-3-14-.03.

49. On numerous occasions between 1979 and the date of this Notice, Southern and Alabama Power have made "modifications" of the Gorgas Plant as defined by the Alabama SIP, ADEM Code 335-3-14-.04(2)(b)(1). These modifications included, but are not limited to, the balanced draft conversion of Unit 10 in 1985, the installation of a new economizer on Unit 10 in 1994, and installation of redesigned air heaters on Unit 10 in 1994.

50. For each of these modifications that occurred at the Gorgas Plant, neither Southern nor Alabama Power obtained a PSD permit pursuant to ADEM Code 335-3-14-.04, a nonattainment NSR permit pursuant to ADEM Code 335-3-14-.05, nor a minor NSR permit pursuant to ADEM Rule 335-3-14-.01. In addition, for modifications after 1992, no documentation was provided to the permitting agency of actual emissions after the modification as required by ADEM Code 335-3-14-.03.

51. On numerous occasions between 1979 and the date of this Notice, Southern and Alabama Power have made "modifications" of the Gaston Plant as defined by the Alabama SIP, ADEM Code 335-3-14-.04(2)(b)(1). These modifications include the replacement of the front reheater for Unit 5 in 1991.

52. For each of the modifications that occurred at the Gaston Plant, neither the Southern Company nor Alabama Power obtained a PSD permit pursuant to ADEM Code 335-3-14-.04, a nonattainment NSR permit pursuant to ADEM Code

335-3-14-.05, nor a minor NSR permit pursuant to ADEM Rule 335-3-14-.01. In addition, for modifications after 1992, no documentation was provided to the permitting agency of actual emission after the modification as required by ADEM Code 335-3-14-.03.

53. On numerous occasions between 1979 and the date of this Notice, Southern and Alabama Power have made "modifications" of the Greene County Plant as defined by the Alabama SIP, ADEM Code 335-3-14-.04(2)(b)(1). These modifications include the replacement of the primary reheater for Unit 2 in 1989.

54. For each of the modifications that occurred at the Greene Plant, neither Southern nor Alabama Power obtained a PSD permit pursuant to ADEM Code 335-3-14-.04, a nonattainment NSR permit pursuant to ADEM Code 335-3-14-.05, nor a minor NSR permit pursuant to ADEM Rule 335-3-14-.01. In addition, for modifications after 1992, no information was provided to the permitting agency of actual emissions after the modification as required by ADEM Code 335-3-14-.03.

55. The modifications at the Barry, Gorgas, Gaston, and Greene County plants do not fall within the "routine maintenance, repair and replacement" exemption found at 40 C.F.R. § 52.21(b)(2)(iii)(a), or ADEM Code 391-3-14-.04(8). Each of these changes was an expensive capital expenditure performed infrequently at the plant that constituted the replacement and/or redesign of a boiler component with a long useful life. In each instance, the change was performed to increase capacity, regain lost capacity, and/or extend the life of the unit. In many instances, the original component was replaced with a component that was substantially redesigned in a manner that increased emissions. That the "routine maintenance, repair and replacement" exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld by the court of appeals in 1990. Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

56. None of these modifications fall within the "increase in hours of operation or in the production rate" exemption found at 40 C.F.R. § 52.21(b)(2)(iii)(f), or ADEM Code 391-3-14-.04(8). This exemption is limited to stand-alone increases in operating hours or production rates, not where such increases follow or are otherwise linked to construction activity. That the hours of operation/rates of production exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld twice by the court of appeals, in 1989 and

in 1990. Puerto Rican Cement Co. v. EPA, 889 F.2D 292 (1st Cir. 1989); Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

57. Each of the modifications at the Barry, Gorgas, Gaston, and Greene County plants resulted in a net significant increase in emissions, as that term is defined in ADEM Code 335-3-14-.04(2)(w), for NOx, SO_2 and/or PM.

58. Therefore, Southern and Alabama Power violated and continue to violate the Alabama SIP by constructing and operating modifications at the Barry, Gorgas, Gaston, and Greene County Plants without the necessary permit required by EPA and by the Alabama SIP.

59. Each of these violations exists from the date of start of construction of the modification until the time that Southern and Alabama Power obtain the appropriate NSR permit and operate the necessary pollution control equipment to satisfy EPA and the Alabama SIP.

E. Watson Plant

60. On numerous occasions between 1979 and the date of this Notice, Southern and Mississippi Power Company have made "modifications" of the Watson Plant as defined by the Mississippi SIP, Mississippi Commission on Natural Resources regulation APC-S-2, Section I. These modifications include the replacement of the economizer at Unit 5 in 1992.

61. For each of the modifications that occurred at the Watson Plant, neither Southern nor Mississippi Power obtained a PSD permit pursuant to Mississippi Commission on Natural Resources regulation APC-S-2, Section IV, a nonattainment NSR permit pursuant to Mississippi Commission on Natural Resources regulation APC-S-2, Section IV, nor a minor permit pursuant to Mississippi Commission on Natural Resources regulation APC-S-2, Section III.

62. None of these modifications fall within the "routine maintenance, repair and replacement" exemption found at 40 C.F.R. § 52.21(b)(2)(iii)(a), or Mississippi Commission on Natural Resources regulation APC-S-2, Section I. Each of these changes was an expensive capital expenditure performed infrequently at the plant that constituted the replacement and/or redesign of a boiler component with a long useful life. In each instance, the change was performed to increase capacity, regain lost capacity, and/or extend the life of the unit. In many instances, the original component was replaced with a component that was substantially redesigned in a manner that increased emissions. That the "routine maintenance, repair and replacement" exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption

was upheld by the court of appeals in 1990. Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

63. None of these modifications fall within the "increase in hours of operation or in the production rate" exemption found at 40 C.F.R. § 52.21(b)(2)(iii)(f), or Mississippi Commission on Natural Resources regulation APC-S-2, Section I. This exemption is limited to stand-alone increases in operating hours or production rates, not where such increases follow or are otherwise linked to construction activity. That the hours of operation/rates of production exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld twice by the court of appeals, in 1989 and in 1990. Puerto Rican Cement Co. v. EPA, 889 F.2D 292 (1st Cir. 1989); Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

64. Each of these modifications resulted in a net significant increase in emissions, as that term is defined in Mississippi Commission on Natural Resources regulation APC-S-2, Section I, from the Watson Plant for NOx, SO_2 and/or PM.

65. Therefore, Southern and Mississippi Power violated and continue to violate the Mississippi SIP by constructing and operating modifications at the Watson Plant without the necessary permit required by EPA and the Mississippi SIP.

66. Each of these violations exists from the date of start of construction of the modification until the time that Southern and Mississippi Power obtain the appropriate NSR permit and operate the necessary pollution control equipment to satisfy EPA and the Mississippi SIP.

F. Crist Plant

67. On numerous occasions between 1979 and the date of this Notice, Southern and Gulf Power Company have made "modifications" at the Crist Plant as defined by both the EPA PSD Regulations, 40 C.F.R. Part 51, Section 52.21(b), and Florida SIP Rule 62-212.400, F.A.C. These modifications include the replacement of the economizer at Unit 7 in 1996.

68. For each of the modifications that occurred at the Crist Plant, neither Southern nor Gulf Power obtained a PSD permit pursuant to 40 C.F.R. § 52.21 and Florida regulation 62-212.400, F.A.C., a nonattainment NSR permit pursuant to 40 C.F.R. § 52.24 and Florida regulation 62-212.500, F.A.C., nor a minor source permit pursuant to the Florida SIP, regulation 62-212.300, F.A.C. In addition, for modifications after 1992, no information was provided to the permitting agency of actual

emissions after the modification is required by 40 C.F.R. § 52.21(b)(21)(v).

69. None of these modifications fall within the "routine maintenance, repair and replacement" exemption found at 40 C.F.R. § 51.21(b)(2)(iii(a), or Florida regulation 62-210.200(183)(a)1a, F.A.C. Each of these changes was an expensive capital expenditure performed infrequently at the plant that constituted the replacement and/or redesign of a boiler component with a long useful life. In each instance, the change was performed to increase capacity, regain lost capacity, and/or extend the life of the unit. In many instances, the original component was replaced with a component that was substantially redesigned in a manner that increased emissions. That the "routine maintenance, repair and replacement" exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld by the court of appeals in 1990. Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

70. None of these modifications fall within the "increase in hours of operation or in the production rate" exemption found at 40 C.F.R. § 52.21(b)(2)(iii)(f), or Florida regulation 62-210.200(183)(a)1a, F.A.C. This exemption is limited to stand-alone increases in operating hours or production rates, not where such increases follow or are otherwise linked to construction activity. That the hours of operation/rates of production exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld twice by the court of appeals, in 1989 and in 1990. Puerto Rican Cement Co. v. EPA, 889 F.2D 292 (1st Cir. 1989); Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

71. None of these modifications fall within the "demand growth" exemption found at 40 C.F.R. § 52.21(b), because for each modification a physical change was performed which resulted in the emissions increase.

72. Each of these modifications resulted in a net significant increase in emissions, as that term is defined in 40 C.F.R. § 51.21(b), from the Crist Plant for NOx, SO_2 and/or PM.

73. Therefore, Southern and Gulf Power violated and continue to violate the Florida SIP by constructing and operating modifications at the Crist Plant without the necessary permit required by the EPA PSD regulations and the Florida SIP.

74. Each of these violations exists from the date of start of construction of the modification until the time that Southern and Gulf Power obtain the appropriate NSR permit and operate the necessary pollution control equipment to satisfy the EPA PSD regulations and the Florida SIP.

M. Plant Kraft

75. On numerous occasions between 1979 and the date of this Notice, Southern and Savannah Power Company have made "modifications" at the Kraft Plant as defined by the Georgia SIP, Section 7 of Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02. These modifications include the balanced draft conversion of Unit 3 in 1985.

76. For each of the modifications that occurred at the Kraft Plant, neither Southern nor Savannah Power obtained a PSD permit pursuant to Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7), a nonattainment NSR permit pursuant to Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.03, nor a minor NSR permit pursuant to Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.03. In addition, for modifications after 1992, no information was provided to the permitting agency of actual emissions after the modification as required by Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7).

77. None of these modifications fall within the "routine maintenance, repair and replacement" exemption found at 40 C.F.R. § 52.21(b)(2)(iii)(a), or Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7). Each of these changes was an expensive capital expenditure performed infrequently at the plant that constituted the replacement and/or redesign of a boiler component with a long useful life. In each instance, the change was performed to increase capacity, regain lost capacity, and/or extend the life of the unit. In many instances, the original component was replaced with a component that was substantially redesigned in a manner that increased emissions. That the "routine maintenance, repair and replacement" exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld by the court of appeals in 1990. Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

78. None of these modifications fall within the "increase in hours of operation or in the production rate" exemption found at 40 C.F.R. § 52.21(b)(2)(iii)(f), or Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7). This exemption is limited to stand-alone increases in operating hours or production rates, not where such increases follow or are otherwise linked to construction activity. That the hours of operation/rates of production exemption does not apply

where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld twice by the court of appeals, in 1989 and in 1990. Puerto Rican Cement Co. v. EPA, 889 F.2D 292 (1st Cir. 1989); Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

79. None of these modifications fall within the "demand growth" exemption found at Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7), because for each modification a physical change was performed which resulted in the emissions increase.

80. Each of these modifications resulted in a net significant increase in emissions, as that term is defined within Georgia Department of Natural Resources Air Quality Control Rule 391-3-1-.02(7), from the Kraft Plant for NOx, SO_2 and/or PM.

81. Therefore, Southern and Savannah Power violated and continue to violate the Georgia SIP by constructing and operating modifications at the Kraft Plant without the necessary permit required by the Georgia SIP.

82. Each of these violations exists from the date of start of construction of the modification until the time that Southern and Savannah Power obtain the appropriate NSR permit and operate the necessary pollution control equipment to satisfy the Georgia SIP.

ENFORCEMENT

Section 113(a)(1) of the Act provides that at any time after the expiration of 30 days following the date of the issuance of this NOV, the Regional Administrator may, without regard to the period of violation, issue an order requiring compliance with the requirements of the state implementation plan or permit, and/or bring a civil action pursuant to Section 113(b) for injunctive relief and/or civil penalties of not more than $25,000 per day for each violation on or before January 30, 1997, and no more than $27,500 per day for each violation after January 30, 1997.

OPPORTUNITY FOR CONFERENCE

Respondents may, upon request, confer with EPA. The conference will enable Respondents to present evidence bearing on the finding of violation, on the nature of violation, and on any efforts it may have taken or proposes to take to achieve compliance. Respondents have the right to be represented by counsel. A request for a conference must be made within 10 days of receipt of this NOV, and the request for a conference or other inquiries concerning the NOV should be make in writing to:

Charles V. Mika ian
Associate Regio al Counsel
Environmental A countability Division
U.S. EPA - Regi n 4
61 Forsyth Stre t, S.W.
Atlanta, Georgi 30303
404-562-9575

By offering the opportunity for a conference or participating in one, EPA does not waive or limit its right o any remedy available under the Act.

Effectiv Date

This NOV shall become effective i mediately upon issuance.

11/2/99
Date

John H. Hankinson, Jr.
for Regional Administrator
EPA, Region 4

Revised plan Received 10/13/02

PLANT CRIST
Unit 7
Compliance Assurance Monitoring Plan
Electrostatic Precipitators for Particulate Matter Control

A. Compliance Approach: Test and Cap

The "Test and Cap" approach is applicable for units with an acceptable compliance margin. Under this approach an opacity cap, as determined by testing, is set at the opacity level which correlates to the permitted particulate limit. This opacity value is also the CAM excursion level. If the curve still does not reach the particulate emission limit, then the cap is set at the maximum opacity on the curve as long as this value does not exceed the six minute opacity limit for the source. A CAM corrective action trigger level is set at 90% of the opacity cap. If the three-hour opacity average approaches the CAM corrective action trigger level, corrective action will be taken to avoid going above the CAM excursion level. A three-hour opacity value greater than the opacity cap would be reported on the semi-annual compliance report as a CAM excursion.

In the presumptively acceptable CAM protocol for precipitators, EPA allows extrapolation of the curve by up to 25% of the highest particulate emissions level tested. While these protocols are not the same, the testing required is identical. In order to avoid exceeding particulate emission limits during CAM testing, Gulf Power will also use this approach.

B. Background

a. Emission Unit:

Description:	Coal-fired boiler
Identification:	Unit 7
Pollution Control Device:	ESP 7
Facility:	Plant Crist 11999 Pate Street Pensacola, FL 32514

b. Applicable Regulation, Emissions Limit, and Monitoring Requirements:

Regulation:	Title V Permit, State regulation
Emissions Limits	
PM:	0.1 lbs/mmbtu
Opacity:	20% (6-minute average)
CAM Opacity Cap:	20% (3-hour block average)
CAM Corrective Action Trigger Level:	18% (3-hour block average)
Monitoring Requirements:	Continuous opacity monitoring system

c. Control Technology: Electrostatic precipitator

C. Monitoring Approach

The key elements of the monitoring approach, including the indicators to be monitored, indicator ranges, and performance criteria are presented in Table 1. The CAM performance indicator is the opacity of the exhaust from the Unit 7 cold-side electrostatic precipitator (ESP) measured in the outlet duct. The CAM corrective action opacity trigger and excursion levels were established based on ESP performance test data collected at varying operating conditions.

The operating conditions tested were normal baseline and one "detuned" condition. The detuned condition was established by turning off or limiting Transformer-Rectifier sections in the ESP. The ESP was detuned to simulate conditions that might occur during ESP malfunctions. The ESP particulate matter emissions at each condition were measured using EPA Method 17. The detailed emissions test reports for each condition are attached.

D. Justification

a. Background

The pollutant-specific emissions unit is a cold-side ESP controlling particulate emissions from a Foster Wheeler wall-fired boiler with a rated steam flow capacity of 3,626,000 lbs/hr. The unit's rated generation capacity is 500^+ MW. The ESP exhaust through an outlet duct before entering the stack. Compliance monitoring and testing is performed in the outlet duct as required by the Title V Permit.

The Unit 7 boiler was placed into service in 1973 and burns Eastern bituminous coal. The ESP consists of two casings 78 feet long by 49 feet high with a nominal gross specific collection area of 384 ft^2/1000 ACFM.

b. Rationale for Selection of Performance Indicators

The selected CAM indicator is the opacity of the Unit 7 cold-side ESP exhaust. Opacity was selected as the performance indicator because as opacity increases, it can be reasonably assumed that PM emissions also increase. Although the correlation between opacity and PM emissions is not exact over all operating conditions, the margin of compliance shown during ESP testing at high opacity levels indicates reasonable assurance that PM emissions should be below the permit limit at a wide range of operating conditions.

c. Rationale for Selection of Opacity Indicator Levels

The corrective action opacity trigger level selected was a three-hour average greater than or equal to 18%. When the opacity is below this level, test data indicates a reasonable assurance that the PM emissions will be less than the permit limit. If the three-hour opacity average increases to 18% or above, action will be taken to bring the average below 18% as soon as possible. If the 3 hour opacity average exceeds 20%, a CAM excursion has occurred.

The CAM corrective action opacity trigger and excursion levels were established by measuring the particulate emissions at different opacity levels in the ESP exhaust. The measured particulate emissions were plotted against the observed opacity and the best fit curve was applied. The highest average opacity tested was 18.6%. At this opacity the PM emission rate was 0.052 lbs/mmbtu. The projected particulate emission rate at 20% opacity using the equation generated by the best fit curve is 0.054 lbs/mmbtu. As can be seen, this is below the permit limit of 0.1 lbs/mmbtu, so the CAM opacity excursion level is set at 20%. The CAM corrective action opacity trigger level is set at 90% of the excursion level to provide a reasonable margin to correct ESP problems before an excursion occurs. The test results are summarized in Table 2 and Figure 1.

The stated intent of the CAM rule is to ensure that control devices are properly operated and maintained. Proper operation of the particulate control device, the electrostatic precipitator, cannot be assessed during unit start-up and shutdown (both controlled and uncontrolled, *e.g.*, during equipment malfunction). During these times, low temperatures and varying fuels cause the precipitators to be naturally unstable. In addition, the CAM testing preformed to develop the opacity cap and corrective action trigger levels was done only under maximum stable loads, with out start-up fuel. CAM monitoring is therefore not required while units are in start-up or shutdown mode.

d. <u>Corrective Actions</u>
Actions taken to correct deficient ESP performance may include the following:
   i. Verify all transformer-rectifiers are in service and working properly.
   ii. Verify flue gas conditioning system is functioning correctly.
   iii. Verify discharge and collecting rappers are working properly.
   iv. Verify ash removal equipment is running properly.

If corrective action fails to lower the opacity, the unit load will be reduced until the opacity is below the CAM excursion level.

e. <u>Rationale for Selection of CAM Averaging Periods</u>
Since the particulate standard is based on a three hour average, an averaging period of three hours was chosen for determination of a CAM excursion. In addition, the CAM corrective action trigger level is set such that action is taken prior to exceeding the CAM opacity cap.

Monitoring Approach

Indicator	Opacity of the ESP exhaust.
Measurement Approach	COMS in the ESP outlet duct.
Indicator Range	The corrective action opacity trigger level is a 3-hour opacity greater than or equal to 18%. If the 3-hour opacity is outside the corrective action trigger level, action will immediately be taken to lower the opacity. An excursion occurs if the 3-hour opacity is greater than 20%.
Data Representativeness	The COMS was installed at a representative location in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
Verification of Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
QA/QC Practices and Criteria	The COMS were initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
Monitoring Frequency	The opacity of the ESP outlet duct is monitored continuously.
Data Collection Procedures	The DAS retains all 6-minute and hourly average opacity data.
Averaging Period	The 6-minute opacity data is used to calculate 3-hour block averages.

Table 1

Crist 7
CAM Test Data Summary

	Baseline (6/14/04)		Condition 1 (6/17/04)	
	Opacity	Particulate	Opacity	Particulate
Run 1	5.0	0.0086	18.5	0.0518
Run 2	5.2	0.0112	18.2	0.0631
Run 3	5.8	0.0043	19.0	0.0414
Average	**5.3**	**0.0080**	**18.6**	**0.0521**

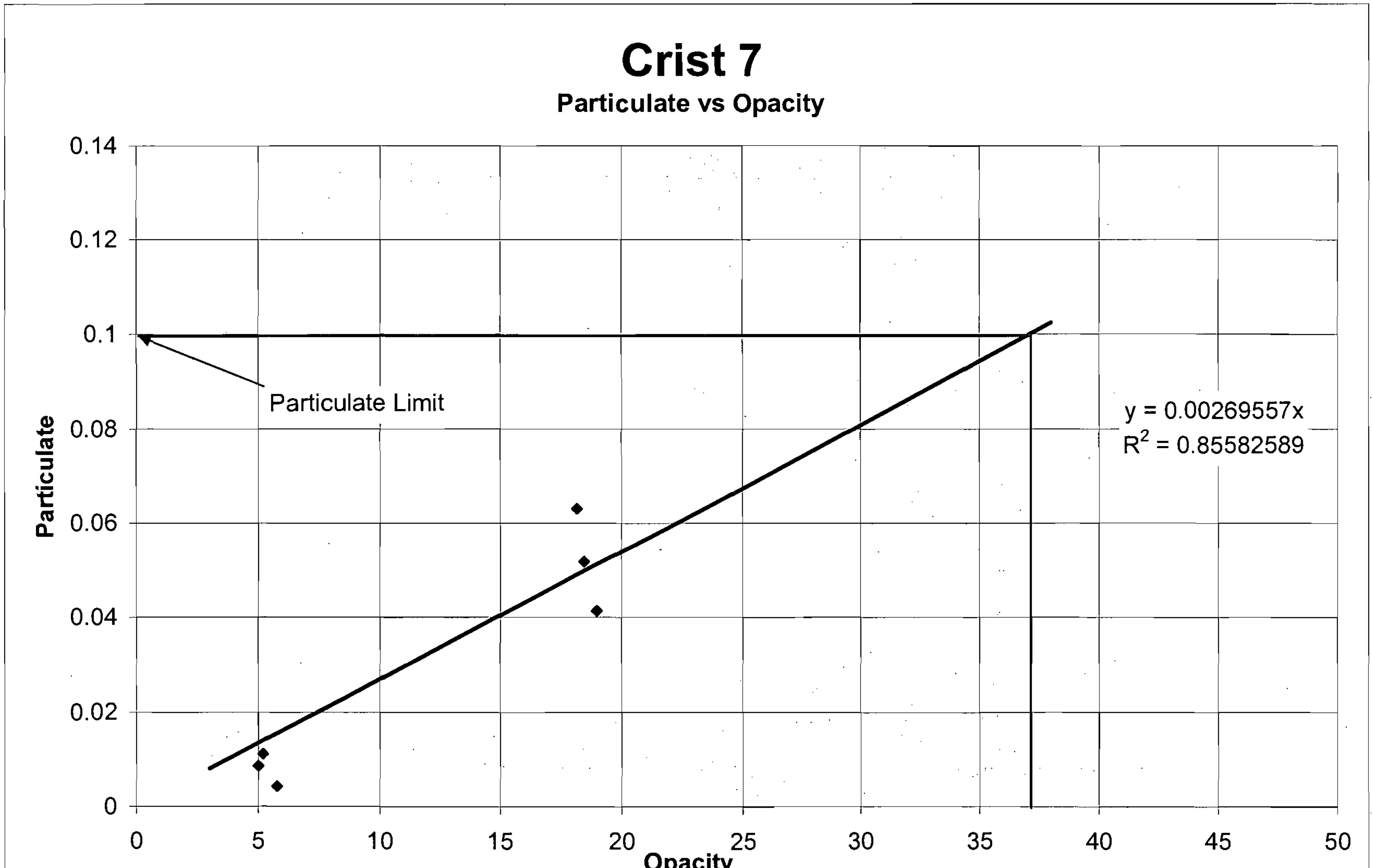
Table 2

- Best fit equation for opacity versus particulate is **y=0.00269557x**
  y=particulate emissions, x=opacity

- **R^2=0.8558**, R^2 is the Coefficient of Determination. It is the percent of variance of one variable explained by the other. The value of 0.8558 shows that 85.58% of the variability in particulate matter is explained by opacity.

- Projected particulate at 20% opacity = **0.00269557(20) = 0.054.**

- Projected particulate is less than the permit limit of 0.1, so the CAM excursion level is set at 20% opacity. The CAM corrective action trigger level is set at 18% opacity (0.9*20%).


Crist 7
Particulate vs Opacity
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
Particulate
Particulate Limit
y = 0.00269557x
R^2 = 0.85582589
0
5
10
15
20
25
30
35
40
45
50
Opacity
Figure 1

>10% for 1hr.

Crist Draft Title V Comments:
Facility ID No: 0330045
October 15, 2004

Comments:

Typo

1) Section I. Facility Information: Subsection A. Facility Description. The description outlines 5 fossil fired steam generators.... The facility has 6; see Statement of Basis.

Check w/ EPA

2) Section I. Facility Information: Section II. Facility-wide Conditions. Item 15. Condition notes reference to Permit Shield in lieu of Condition 52 of Appendix TV-4, Conditions. Gulf Power sees no need for this condition and any reference to on-going litigation in a permit. There are no such litigations on-going with Gulf Power. Please remove condition.

Add clarifier for Gas

3) Section III. Emissions Units and Conditions. A.21. Heat Input. Please add to A.21 reference to recordkeeping provisions for daily records for fuel consumption, i.e. A. 31. Please note that for A. 31 (Units 2 & 3) natural gas is not currently referenced, only solid and liquid fuel. The condition as written only addresses fuel oil for these units.

? discuss

4) Section III Emissions Units and Conditions. A.31 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption.

5) Section III Emissions Units and Conditions. B.26. Heat Input. Please add to B.26 reference to recordkeeping provisions for daily records for fuel consumption, i.e. B.33.

reasonable

6) Section III Emissions Units and Conditions. ~~B.26~~ B.33 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption. Gulf Power will meet greater than 95% daily sampling rate.

?

7) Section III Emissions Units and Conditions. C.34. Heat Input. Please add to C.34 reference to recordkeeping provisions for daily records for fuel consumption, i.e. C.41.

?

8) Section III Emissions Units and Conditions. C.41 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption. Gulf Power will meet greater than 95% daily sampling rate.

95% ok

9) Section IV. Acid Rain Part. Subsection A. E.U. ID. Please add Unit 001 to all references in this section. Gulf Power retains 35 SO2 allowances per year for Unit 001 even after retirement under the Acid Rain Program.

Correct

10) Section IV. Acid Rain Part. Subsection A. 6. Please update DR list. Mr. W. Paul Bowers is currently the DR. Delete under alternative designated representative, Mr. ~~Robert G. Moore~~ and substitute Mr. Gene L. Ussery, Jr.

?

11) Appendix CAM, Compliance Assurance Monitoring Plan. Emissions Unit 007. Please revise the averaging time from 6 minutes to 1 hour for excursion and 6 minutes to 3 hours for exceedance as referenced in the Indicator Range in Table IV. There is no justification for adoption of less than a 3 hour averaging period for monitoring CAM for particulate matter. This unit was CAM tested at 18% opacity at 0.052 lb/mmbtu per EPA CAM protocol.

12) Appendix CAM, Compliance Assurance Monitoring Plan. Emissions Unit 004, 005, 006 & 007. Please clarify that startup, shutdown and other excess emission exemptions do not apply to CAM.

Scholz Draft Title V Comments:
Facility ID No: 0630014
October 15, 2004

Comments:

See Crist

1. Section III Emissions Units and Conditions. A.25. Heat Input. Please add to A.25 reference to recordkeeping provisions for daily records for fuel consumption, i.e. A.32.
2. Section III Emissions Units and Conditions. A.32 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (midnight to midnight) of fuel consumption. Gulf Power will meet greater than 95% daily sampling rate.
3. Section IV. Acid Rain Part. Subsection A. 6. Please update DR list. Mr. W. Paul Bowers is currently the DR. Delete under alternative designated representative, Mr. Robert G. Moore and substitute Mr. Gene L. Ussery, Jr.
4. Appendix CAM, Compliance Assurance Monitoring Plan. Emissions Unit 001 & 002. Please clarify that startup, shutdown and other excess emission exemptions do not apply to CAM.

A.37 Clarify 5 yr date add AC#. So cite & clarify only unit 2?

Lansing Smith Draft Title V Comments:
Facility ID No: 0050014
October 15, 2004

Comments:

? No oil generally no cons ?

1. Statement of Basis. Please note that Lansing Smith Units 4 & 5 do not utilize opacity monitors for compliance as stated in the 6th paragraph.
2. Section III Emissions Units and Conditions. A.25. Heat Input. Please add to A.25 reference to recordkeeping provisions for daily records for fuel consumption, i.e. A.32.

?

3. Section III Emissions Units and Conditions. A.32 Recordkeeping and Reporting Requirements. Please note that daily means 24 hour block (~~midnight to midnight~~) of fuel consumption. Gulf Power will meet greater than 95% sampling rate. ok

remove

4. Section III Emissions Units and Conditions. A.39 Ambient Monitoring Requirements. Please remove condition. Gulf Power no longer volunteers to monitor ambient air conditions at this facility.

Periodic Monitoring from Negotiations research

5. Section III Emissions Units and Conditions. B.18 Periodic Monitoring Requirements. Please revise condition to the latest acceptable language approved by the Department noting VE tests after 400 hours of operation on fuel oil and delete every 150 hours of operation thereafter. Also, delete 20 days of exceeding such operating hours and substitute within the next fiscal year. Test every 5 yrs

Make consistent w/ AC.

6. Section III Emissions Units and Conditions. C.5 Permitted Capacity. (a) Combustion Turbine Capacity. Please correct the description of the unit from HHV to LHV as outlined in the statement of basis and in the general description page (see Subsection C under E.U. 4& 5) of the draft permit.

Check to match A.C. different for NOx vs. opacity

7. Section III Emissions Units and Conditions. C.15 Excess Emissions, Please add language from the existing Title V permit under C.15 to this permit. "Excess Emissions resulting from startup, shutdown, or malfunction of any emissions unit shall be permitted provided the best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. (Rule 62-620.700(1), F.A.C.). There is no reason to have deleted this condition." No Excess Emissions allowed for NOx per A.C. Permit.

check

8. Appendix CAM, Compliance Assurance Monitoring Plan. Emissions Unit 001& 002. Please change for Unit 001 the excursion limitation from 30% opacity to 32% as outlined in the application using EPA acceptable CAM protocol. Also, please change the exceedance notation from 34% opacity to 36% as outlined in the application using EPA acceptable protocol. Please clarify that startup, shutdown and other excess emission exemptions do not apply to CAM.

Update as outlined

9. Gulf Power has discovered several errors in the tank listing under the Insignificant Emissions List which need to be revised. Please find attached, the corrected Appendix I-1 List of Insignificant Emissions Units and/or Activities for Lansing Smith.

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

Gulf Power Company | **DRAFT Permit No.:** 0050014-010-AV
Lansing Smith Electric Generating Plant | **Facility ID No.:** 0050014

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

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

	State Registration Number	Contents	Size (Gallons)
1.	Tank #1	#2 Diesel - Lighter Oil	25,000
2.	Tank #3	#2 Diesel - CT Fuel Oil	200,000
3.	Tank #4	#2 Diesel - CT Fuel Oil	200,000
4.	Tank #5	#2 Diesel - CT Fuel Oil	200,000
5.	---	Lube Oil	1,000
6.	Tank #7	Used Oil	2,100
7.	---	Lube Oil	581
8.	---	Lube Oil	560
9.	---	Lube Oil	560
10.	---	Lube Oil	560
11.	---	Lube Oil	560
12.	Tank #13	Lube Oil	6,000
13.	Tank #14	Lube Oil	6,000
14.	Tank #15	Lube Oil	6,000
15.	Tank #16	Sulfuric Acid	4,000
16.	--	Maintenance Area, Used Oil	500
17.	--	Maintenance Area, Used Oil	500
18.	--	Tractor Shed Area Used Oil	300
19.	--	Fire Pump Diesel Fuel (2)	500
20.	--	Chlorine (13)	1 ton
21.	--Delete	Used Oil	250
22.	--Delete	Used Oil	500
21	Tank # 18	Diesel Sludge Tank	570
22	---	Gas Condensate Tank U-3	500
23	---	Emergency Generator Diesel	500

Miscellaneous

23. Fire Safety Equipment - Exempted by Rule 62-210.300(3)(a)22., F.A.C.
24. Vacuum Pumps - Exempted by Rule 62-210.300(3)(a)9., F.A.C.
25. Laboratory Equipment - Exempted by Rule 62-210.300(3)(a)15., F.A.C.
26. Welding Equipment - Exempted by Rule 62-210.300(3)(a)16., F.A.C.
27. Gulf Power Company Generated Non-hazardous Boiler Chemical Cleaning Wastes

(Not to exceed 50 gallons per minute)

24 hr block in order to demonstrate
compl. w/ hourly limit.

Holtom, Jonathan

From: Waters, Glenn D. [GDWATERS@southernco.com]
Sent: Thursday, April 22, 2004 10:13 AM
To: Holtom, Jonathan
Subject: Crist SO2 Rate

Looks like Gulf Power will accept the 2.4 lb/Mbtu SO2 for Plant Crist. The executives however want some PR out of the reduction so I will let Mr. Vick work that out with Mary Jean or Allan. What is the next step, a letter from us to you. Does it need to signed by the RO? If so, we will prepare it for my next meeting with him on April 29? Dwain

G. Dwain Waters,QEP
Air Quality Programs Supervisor
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328
Phone: (850) 444-6527
Cell: (850) 336-6527
Pager: (850) 469-4076
gdwaters@southernco.com

COMPLIANCE REPORT AND PLAN
CRIST ELECTRIC GENERATING PLANT

The following compliance report and plan is provided to document the status of compliance of Plant Crist addressed in this Application for Air Permit. More specifically, this plan is being submitted as a proposed schedule of compliance to provisions outlined in the FDEP-Gulf Power Ozone Reduction Agreement which requires Plant Crist to retire Units 1,2 & 3 before May 1, 2006, install an SCR on Unit 7, and other strategies on the remaining coal fired units in order to meet an overall plant wide NOx average of 0.20 lbs/mmbtu. The following actions are scheduled to be taken to achieve compliance with enforceable milestones.

Item	Action	Schedule
1) Retirement of Crist 1,2 & 3	Submit Retirement Form	On or before May 1, 2006
2) Unit 7		
Install SCR	Startup SCR	On or before May 1, 2005
	Meet 330045-008-AC Requirements	On or before May 1, 2005
	Meet 0.15 lb/mmbtu NOX limit	May 1, 2005 to May 1, 2006
3)* Unit 6		
Install SNCR on Crist 6	Startup SNCR	On or before May 1. 2006
New Low Burners	Startup Low NOx Burners	On or before May 1, 2006
Over-fired Air Control	Startup Over-fired Air Control	On or before May 1, 2006
4)* Unit 4 & 5		
Install SNCR as needed	Startup & Operate as needed	On or before May 1, 2006
5) Facility Wide NOx Rate	Meet 0.20 lb/mmbtu NOx Average Based on 30 day average as outlined in the FDEP-Gulf Ozone Agreement	May 1, 2006

***Items 3 & 4 above have been proposed to FDEP as strategies to meet the FDEP-Gulf Power Ozone Agreement. Upon approval, these items will be incorporated into a construction permit.**

W. Paul Bowers
President

Southern Company Generation
and Energy Marketing
600 North 18th Street/15N-8170
15th Floor
Post Office Box 2641
Birmingham, Alabama 35291

Tel 205.257.5355
Fax 205.257.0526
wpbowers@southernco.com

SOUTHERN COMPANY
Energy to Serve Your World®

June 15, 2004

RECEIVED
JUN 17 2004
BUREAU OF AIR REGULATION

Mr. Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Air Resources Management Division
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399 – 2400

Dear Mr. Fancy:

This letter is provided in accordance with the requirements outlined in Rule 62-213.440(2), Florida Administrative Code (F.A.C.), and Appendix CP-1 of the Crist Electric Generating Plant, Scholz Electric Generating Plant, and the Lansing Smith Electric Generating Plant permits. On November 18, 2003, Southern Company submitted a revised Southern Company Phase II NOx Averaging Plan to the States of Alabama, Florida, Georgia, and Mississippi and to Jefferson County, Alabama, with copies to the U.S. Environmental Protection Agency. A copy of this revised plan for the State of Florida is attached.

The existing Southern Company Phase II NOx Averaging Plan is dated April 15, 1999, for the 5-year period 2000 – 2004. This revised plan replaces that plan and covers the period 2004 – 2008.

This revised Southern Company NOx averaging plan has been approved by the Alabama Department of Environmental Management, Georgia Environmental Protection Division, Mississippi Department of Environmental Quality, and the Jefferson County, Alabama, Department of Health. In conjunction with final approval of the averaging plan, the agencies have or are in the process of updating permits for these units to incorporate this new plan.

This certification is based on information and belief formed after reasonable inquiry. To the best of my knowledge, the statements and information in this document are true, accurate, and complete as required by 62-213.420 (4) F.A.C.

If you have questions about the plan or the status of approval, please contact Mr. Danny Herrin, Manager, Environmental Compliance Strategies and Permitting, Southern Company Generation, at (205) 257-6468.

Sincerely,

W. Paul Bowers

Attachment:

cc: Ronald W. Gore, Alabama Department of Environmental Management
Ronald C. Methier, Georgia Environmental Protection Division
Dwight Wylie, Mississippi Department of Environmental Quality
Wayne Studyvin, Jefferson County Department of Health
R. Doug Neeley, U.S. Environmental Protection Agency
Robert Miller, U.S. Environmental Protection Agency

Florida Department of Environmental Protection

Phase II NO_x Averaging Plan

For more information, see instructions for DEP Form No. 62-210.900(1)(a)4.and refer to 40 CFR 76.11

This submission is: [ ] New [X] Revised

STEP 1

Identify the units participating in this averaging plan by plant name, state, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
See Page 3.					

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
0.47	≤	0.47

$$\frac{\sum_{i=1}^{n} (R_{Li} \, x \, HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n} [R_{li} \, x \, HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emmision limitation for unit i, in 16/mmBtu, as specified in column (b) of Step 1;

R_{li} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

Southern Company Averaging Plan Participating Plants

STEP 3

Mark one of the two options and enter dates.

☐ This plan is effective for calendar year ____________ through calendar year ______________ unless notification to terminate the plan is given.

[X] Treat this plan as [5] identical plans, each effective for one calendar year for the following calendar years: 2004, 2005, 2006, 2007 and 2008 unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_x under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and
(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,
(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or
(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.
(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

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

Name W. Paul Bowers	
Signature W. Paul Bowers	Date 18 NOV 03'

Southern Company Averaging Plan Participating Plants
Plant Name (from Step 1) as Listed in Step 1.

NO$_x$ Averaging - Page 3

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Barry	AL	1	0.40	0.57	9,899,353
Barry	AL	2	0.40	0.57	8,827,877
Barry	AL	3	0.40	0.57	16,115,170
Barry	AL	4	0.40	0.45	26,192,590
Barry	AL	5	0.40	0.45	51,553,955
Bowen	GA	1	0.45	0.42	45,308,998
Bowen	GA	2	0.45	0.43	44,124,507
Bowen	GA	3	0.45	0.43	59,801,873
Bowen	GA	4	0.45	0.43	60,182,168
Branch	GA	1	0.68	0.99	13,188,369
Branch	GA	2	0.50	0.72	18,342,165
Branch	GA	3	0.68	0.84	26,905,201
Branch	GA	4	0.68	0.84	30,127,590
Crist	FL	4	0.45	0.52	5,591,320
Crist	FL	5	0.45	0.60	5,479,586
Crist	FL	6	0.50	0.45	21,086,630
Crist	FL	7	0.50	0.45	34,569,955
Daniel	MS	1	0.45	0.33	30,626,415
Daniel	MS	2	0.45	0.33	40,588,498
Gadsden	AL	1	0.45	0.70	2,711,382
Gadsden	AL	2	0.45	0.70	3,120,871
Gaston	AL	1	0.50	0.52	18,858,472
Gaston	AL	2	0.50	0.52	16,624,702
Gaston	AL	3	0.50	0.52	18,430,084
Gaston	AL	4	0.50	0.52	18,740,418
Gaston	AL	5	0.45	0.48	47,511,274
Gorgas	AL	6	0.46	0.55	4,410,470
Gorgas	AL	7	0.46	0.55	4,567,585
Gorgas	AL	8	0.40	0.50	9,965,627
Gorgas	AL	9	0.40	0.50	9,120,885
Gorgas	AL	10	0.40	0.35	45,358,619

Southern Company Averaging Plan Participating Plants as Listed in Step 1.
Plant Name (from Step 1)

NO$_x$ Averaging - Page 4

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Greene Co	AL	1	0.68	0.82	17,363,013
Greene Co	AL	2	0.46	0.50	19,145,604
Hammond	GA	1	0.50	0.83	6,007,234
Hammond	GA	2	0.50	0.83	5,605,352
Hammond	GA	3	0.50	0.83	6,386,989
Hammond	GA	4	0.50	0.45	26,721,145
Kraft	GA	1	0.45	0.58	3,578,077
Kraft	GA	2	0.45	0.58	3,745,253
Kraft	GA	3	0.45	0.58	7,231,649
L. Smith	FL	1	0.40	0.62	11,275,531
L. Smith	FL	2	0.40	0.44	9,250,882
McDonough	GA	1	0.45	0.42	18,180,480
McDonough	GA	2	0.45	0.42	17,346,682
McIntosh	GA	1	0.50	0.86	11,087,042
Miller	AL	1	0.46	0.37	47,413,738
Miller	AL	2	0.46	0.37	52,747,691
Miller	AL	3	0.46	0.28	44,422,395
Miller	AL	4	0.46	0.28	47,115,364
Mitchell	GA	3	0.45	0.62	6,652,246
Scherer	GA	1	0.40	0.50	52,573,864
Scherer	GA	2	0.40	0.50	55,563,600
Scherer	GA	3	0.45	0.29	53,365,333
Scherer	GA	4	0.40	0.30	70,093,731
Scholz	FL	1	0.50	0.68	2,365,039
Scholz	FL	2	0.50	0.77	2,429,511
Wansley	GA	1	0.45	0.41	53,141,279
Wansley	GA	2	0.45	0.42	49,741,786
Watson	MS	4	0.50	0.50	16,243,776
Watson	MS	5	0.50	0.65	35,347,433
Yates	GA	1	0.45	0.48	4,977,822
Yates	GA	2	0.45	0.48	4,976,029
Yates	GA	3	0.45	0.48	4,080,042
Yates	GA	4	0.45	0.40	6,554,969
Yates	GA	5	0.45	0.40	6,415,254
Yates	GA	6	0.45	0.33	19,199,860
Yates	GA	7	0.45	0.30	15,577,083

One Energy Place
Pensacola, Florida 32520

Tel 850.444.6111

RECEIVED
MAR 14 2005
BUREAU OF AIR REGULATION

GULF POWER
A SOUTHERN COMPANY

Certified Mail

March 3, 2005

Ms. Sandra Veazey
Florida Department of Environmental Protection
Northwest District
160 Governmental Center
Pensacola, FL 32501-5794

Dear Ms. Veazey:

RE: CRIST ELECTRIC GENERATING PLANT
RESPONSIBLE OFFICIAL REQUEST CHANGE
PERMIT No: 0330045-009-AV

Attached, please find a revised "Responsible Official Notification Form" for Gulf Power's Crist Electric Generating Plant. This request is pursuant to a personnel change within Gulf Power for the Vice-President, Power Generation from Gene L. Ussery, Jr. to Penny M. Manuel.

If you have any questions or need further information regarding this change of Responsible Official for the Crist Electric Generating Plant, please call me at (850) 444-6527.

Sincerely,

Dwain Waters, QEP

G. Dwain Waters, QEP
Air Quality Programs Supervisor

cc: w/att: Jim Vick, Gulf Power Company
Bernard Jacob, Gulf Power Company
Joe Martin, Gulf Power Company
Terry Wright, Gulf Power Company
John Dominey, Gulf Power Company
Brian Toth, Southern Company Services
Gary Perko, HGSS

Department of Environmental Protection

RECEIVED
MAR 14 2005
BUREAU OF AIR REGULATION

Division of Air Resource Management

RESPONSIBLE OFFICIAL NOTIFICATION FORM

Note: A responsible official is not necessarily a designated representative under the Acid Rain Program. To become a designated representative, submit a certificate of representation to the U.S. Environmental Protection Agency (EPA) in accordance with 40 CFR Part 72.24.

Identification of Facility

1. Facility Owner/Company Name: **Gulf Power Company**	
2. Site Name: **Crist Electric Generating Plant**	3. County: **Escambia**
4. Title V Air Operation Permit/Project No. *(leave blank for initial Title V applications)*: **0330045-009-AV**	

Notification Type *(Check one or more)*

[ ] **INITIAL**: Notification of responsible officials for an initial Title V application.
[ ] **RENEWAL**: Notification of responsible officials for a renewal Title V application.
[X] **CHANGE**: Notification of change in responsible official(s).
Effective date of change in responsible official(s) **03/01/05**

Primary Responsible Official

1. Name and Position Title of Responsible Official: **Penny M. Manuel (pmmanuel@southernco.com)**

2. Responsible Official Mailing Address:
Organization/Firm: **Gulf Power Company**
Street Address: **One Energy Place**
City: **Pensacola** State: **Florida** Zip Code: **32520-0100**

3. Responsible Official Telephone Numbers:
Telephone: **(850) 444-6383** Fax: **(850) 444-6744**

4. Responsible Official Qualification *(Check one or more of the following options, as applicable)*:

[X] For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
[ ] For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
[ ] For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
[ ] The designated representative at an Acid Rain source.

5. Responsible Official Statement:

I, the undersigned, am a responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this notification. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this notification are true, accurate and complete. Further, I certify that I have authority over the decisions of all other responsible officials, if any, for purposes of Title V permitting.

Penny Manuel — 3-4-5

Signature — Date

DEP Form No. 62-213.900(8)
Effective: 6-02-02

SANDERS ENGINEERING & ANALYTICAL SERVICES, INC.

PARTICULATE EMISSIONS TEST REPORT
CAM CONDITION 1

FOR

GULF POWER COMPANY
Plant Crist, Unit 7
Pensacola, Florida

SEAS

June 17, 2004

1568 LEROY STEVENS ROAD
MOBILE, ALABAMA 36695
(251) 633-4120
FAX: (251) 633-2285
E-MAIL: sanders@sandersengineering.com

REPORT CERTIFICATION

I have reviewed the "Particulate Emissions Test Report – CAM Condition 1" for the testing performed for Gulf Power Company on Unit 7 located at the Plant Crist facility in Pensacola, Florida. I hereby certify that it is authentic and accurate to the best of my knowledge.

Date: 6/29/04

Signature: Johnny W. Sanders

Johnny W. Sanders, P.E. M.P.H.
President

TABLE OF CONTENTS

LIST OF TABLES

ILLUSTRATIONS

1. INTRODUCTION

Sanders Engineering & Analytical Services, Inc. (SEAS) performed Compliance Assurance Monitoring (CAM) for particulate emissions testing during Condition 1 on June 17, 2004,, for Gulf Power Company on Unit 7 located at the Plant Crist facility in Pensacola, Florida. The testing was performed in accordance with the applicable U.S. EPA procedures specified at **40 CFR, Part 60, Appendix** A, **Methods 1, 2, 3a, 4, and 17**. Further discussion of the test methods is included later in the report.

The purpose of the testing was to demonstrate compliance with the rules and regulations of the U. S. Environmental Protection Agency, and to meet the necessary requirements contained in the permit to operate issued by the Florida Department of Environmental Protection. The tests were conducted by Mr. John Rampulla, Mr. John Wilson, and Mr. Richard Reynolds of Sanders Engineering & Analytical Services, Inc., and were coordinated with Mr. Kevin Beaty of Gulf Power Company. The Florida Department of Environmental Protection was notified so a representative could be present to observe the testing.

The results of the testing prove the unit to be in compliance with the particulate emission limitations contained in the permit while operating under CAM Condition 1 issued by the Florida Department of Environmental Protection.

2. DESCRIPTION OF SAMPLING PROGRAM

The sampling program consisted of particulate emissions testing in compliance with US EPA methods. The following is a brief description of this type of testing. The particulate sample was extracted from the stack isokinetically through a stainless steel nozzle and probe onto a pre-weighed glass fiber filter. The sample was taken at a series of points across the stack. Each point represented an equal area of stack. The isokinetic sampling rate and volumetric flow rate was monitored by an S-type pitot tube attached to the probe. Calibrations of the particulate testing equipment including pitots, thermocouples, magnehelics, and other measurement devices are included in Appendix A. A detailed description of the testing procedures and schematic of the sampling train is presented in Section 6. The field data sheets for this testing are presented in Appendix B. Sample calculations of Run 1 are presented in Appendix C. The precipitator data as supplied by Gulf Power Company is presented in Appendix D.

3. SUMMARY AND DISCUSSION OF RESULTS

There were no unusual problems encountered during the performance of the testing. During the performance of the CAM Condition 1 testing, the average heat input, as based on F-factor calculations, was 4610 million Btu per hour. The results of the testing show the particulate emission rate for the unit during CAM Condition 1 operations is 0.0521 pounds per million Btu compared to an allowable limit contained in the permit of 0.1 pounds per million Btu. The results of the particulate emissions testing for each of the runs are summarized in Table I. A graphical representation of the results for each of the runs is presented in Figure 1.

The results of the testing prove the unit to be in compliance with the particulate emission limitations contained in the permit while operating under CAM Condition 1 issued by the Florida Department of Environmental Protection.

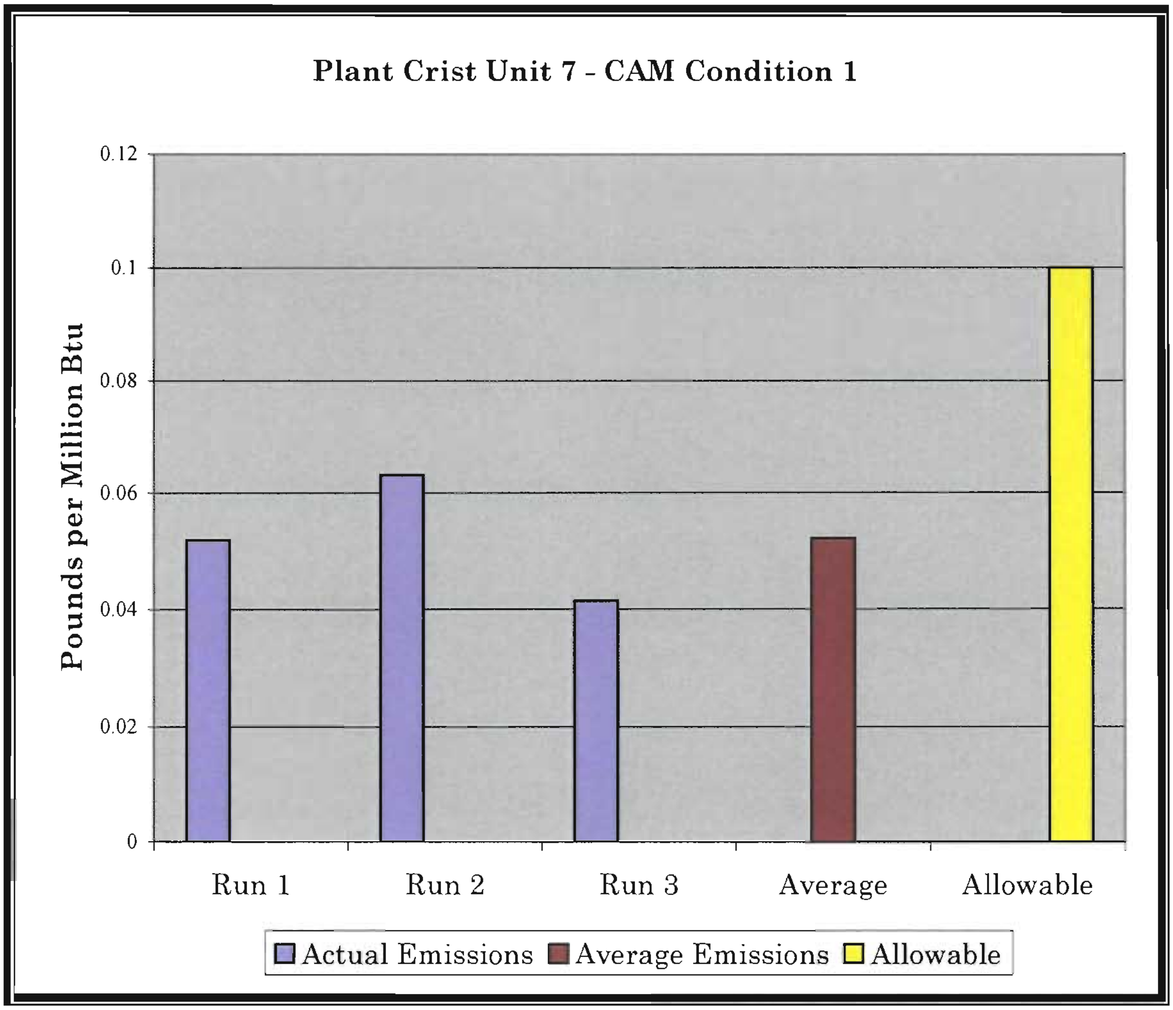
TABLE I. SUMMARY OF PARTICULATE EMISSIONS TEST RESULTS
GULF POWER COMPANY
PLANT CRIST, UNIT 7
CAM CONDITION 1

Title of Run		RUN 1	RUN 2	RUN 3
Date	Month/Day/Year	6/17/2004	6/17/2004	6/17/2004
Sampling Time -Start	Military	1358	1632	1752
Sampling Time -Stop	Military	1504	1740	1858
Oxygen F Factor	SDCF/MMBTU	9780	9780	9780
Stack Static Pressure	Inches Water	1.50	1.50	1.50
Barometric Pressure	Inches Mercury	30.10	30.10	30.10
Meter Correction Factor	dimensionless	1.011	1.011	1.011
Oxygen Concentration	Mole Percent O2	6.3	6.5	6.8
Carbon Dioxide Concentration	Mole Percent CO2	13.5	14.0	14.0
Volume of Gas Metered	Actual Cubic Feet	34.790	38.390	37.280
Volume of Water Collected	Milliliters	69.00	78.0	85.0
Sampling Time	Minutes	60	60	60
Nozzle Diameter	Inches	0.190	0.190	0.190
Weight of Solids Collected	Milligrams	57.0	75.5	46.9
Area of Stack	Square Feet	366.2625	366.2625	366.2625
Avg. Sqr. Root Velocity Pressure	Inches Water	1.1312	1.2359	1.2296
Average Orifice Pressure (ΔH)	Inches Water	1.2	1.4	1.4
Average Stack Temperature	Degrees F	330.3	331.8	329.6
Average Meter Temperature	Degrees F	93.5	93.9	96.6

Calculations

		RUN 1	RUN 2	RUN 3	*3 Runs* Average
Volume of Gas Sampled	Standard Dry Cubic Feet	33.861	37.358	36.098	35.772
Molecular Wt. of Stack Gas	LB/LB-MOLE	29.326	29.381	29.264	29.324
Water vapor in Stack Gas	Percent	8.8	8.9	10.0	9.2
Average Stack Gas Velocity	Feet per second	76.70	83.81	83.43	81.32
Stack Gas Flow Rate	Actual Cubic Feet Per Minute	1,685,597	1,841,802	1,833,522	1,786,974
Stack Gas Flow Rate	Standard Wet Cubic Feet Per Minute	1,136,887	1,239,784	1,237,651	1,204,774
Stack Gas Flow Rate	Standard Dry Cubic Feet Per Minute	1,037,385	1,128,842	1,114,162	1,093,463
Particulate Concentration	Grains per Standard Dry Cubic Foot	0.0259	0.0311	0.0200	0.0257
Particulate Concentration	Grains per Actual Cubic Foot	0.0160	0.0191	0.0122	0.0157
Particulate Emission Rate	Pounds per Hour	230.5	301.1	191.1	240.9
Particulate Emission Rate	Pounds per Million Btu (O2 F Factor)	**0.0518**	**0.0631**	**0.0414**	**0.0521**
Heat Input (O2 F Factor)	Million Btu per Hour	4,446	4,772	4,611	4,610
Isokinetic Rate	Percent	101.2	102.6	100.4	101.4

FIGURE 1. GRAPHICAL REPRESENTATION OF PARTICULATE EMISSIONS TEST RESULTS



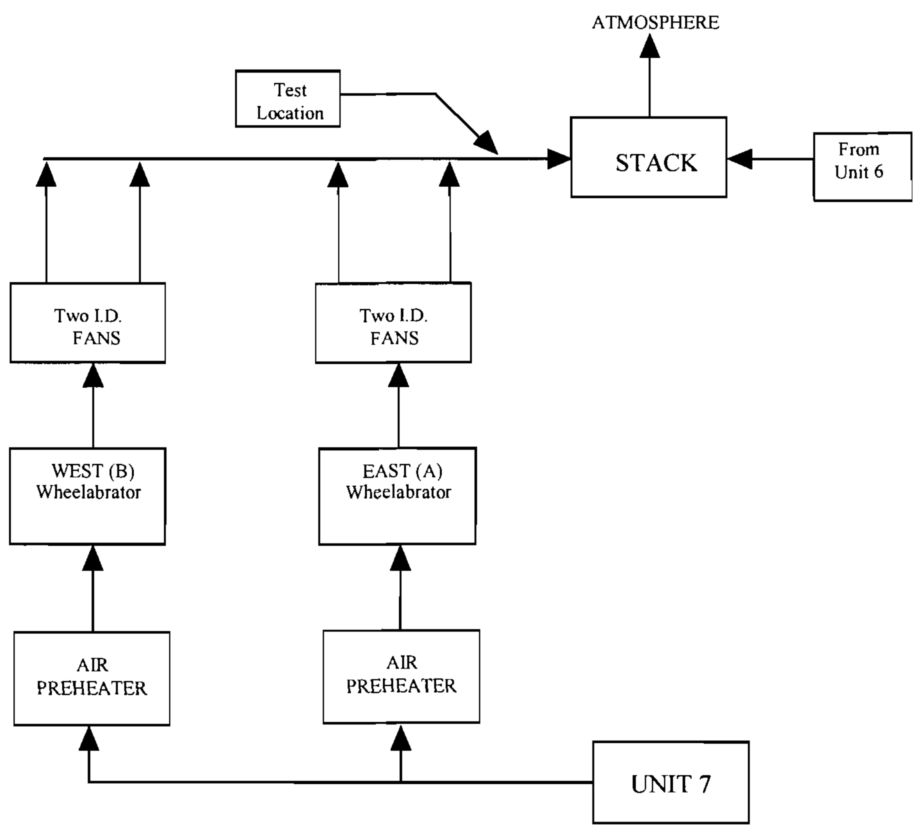
4. PROCESS DESCRIPTION

The process consists of a steam electric generating unit firing bituminous coal for the production of electric energy. The coal is received by barge, and loaded directly onto the conveyor feeding the plant or onto the stockpile and later loaded onto the conveyor belt transporting the coal to the plant. The coal from the conveyor is loaded into bunkers capable of holding between 36 to 48 hours supply of coal. The coal is then fed to pulverizing mills before being fired in the unit through the burners. Upon combustion of the coal in the fire box, approximately 20 percent of the ash falls to the bottom of the boiler and is removed by the ash removal system. The remaining 80 percent exits with the flue gases through the heat exchange and economizer sections of the furnace, and is collected by electrostatic precipitators.

4.1. Source Air Flow

As shown in Figure 2, the flue gases exit the boiler and are separated into ducts A and B before entering air preheaters. They are then routed to a cold side electrostatic precipitator. The flue gases exiting the cold side electrostatic precipitator are exhausted through a stack into the atmosphere.

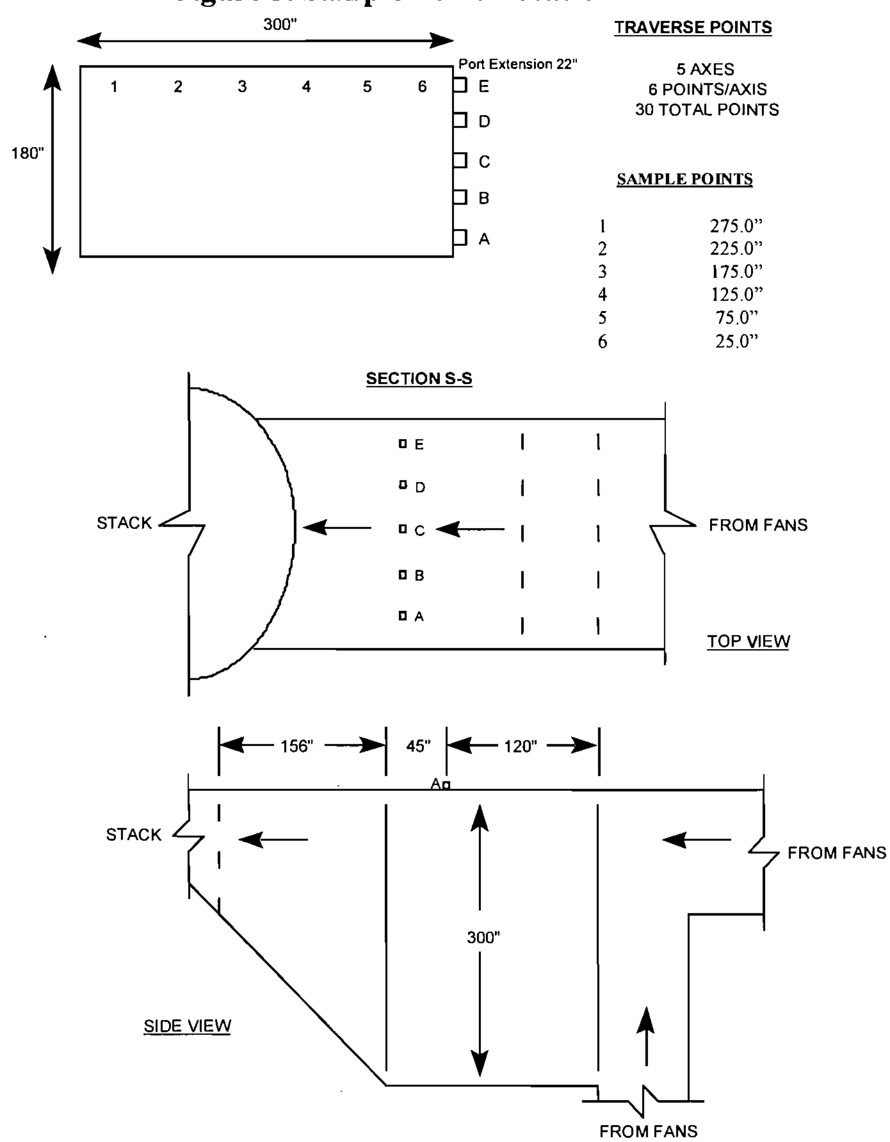
Figure 2. Air Flow Schematic



5. SAMPLE POINT LOCATION

The sample point locations and outlet duct schematic are presented in Figure 3. Method 1 was used for determination of the number and location of sampling points. The minimum number of points (25) required for rectangular stacks was met by sampling a total of 30 points. A new stack area of 366.2625 is used in all calculations. The new area is derived from the unit 7 default wall affect factor.

Figure 3. Sample Point Locations

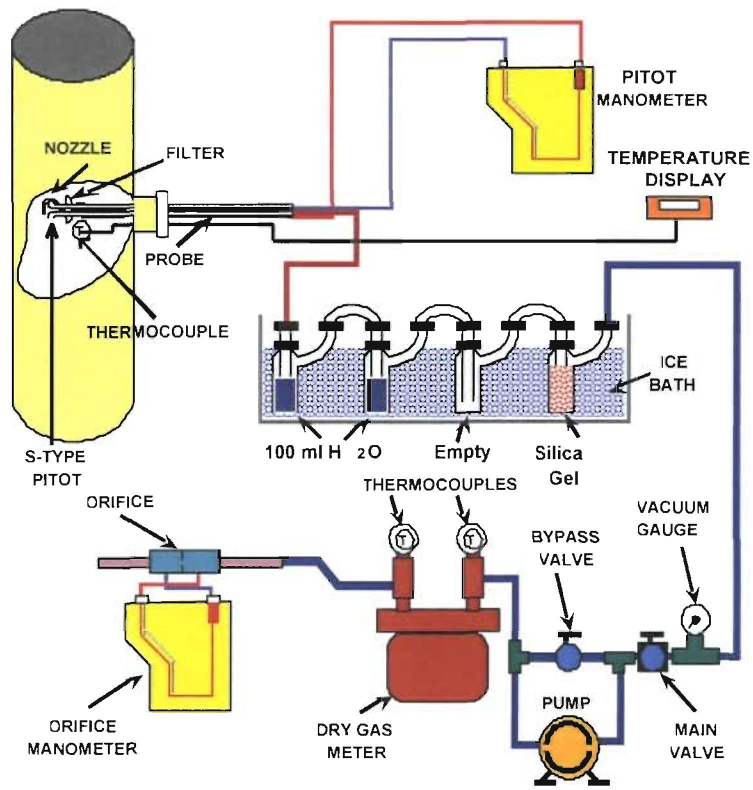


6. PARTICULATE SAMPLING PROCEDURE (EPA Method 17)

The sampling procedure utilized is that specified in **40 CFR, Part 60, Appendix A, Method 17**. A brief description of this procedure is as follows:

The first impingers were partially filled with 100 milliliters of deionized water. The next impinger was left empty to act as a moisture trap. Preweighed 6 to 16 mesh indication silica gel was added to the last impinger. The sampling equipment manufactured by Lear Siegler (Model 100) or Sanders Engineering (Model 200) was assembled as shown in the attached drawing. The system was leak checked by plugging the inlet to the nozzle and pulling a 15 inch mercury vacuum. A leakage rate not in excess of 0.02 cubic feet per minute was considered acceptable.

Figure 4. Particulate Sampling Train



The inside dimensions of the stack liner were measured and recorded. The required number of sampling points was marked on the probe for easy visibility. The range of velocity pressure, the percent moisture, and the temperature of the effluent gases were determined. From this data, the correct nozzle size and the nomograph multiplication factor were determined.

Crushed ice was placed around the impingers. The nozzle was placed on the first traverse point with the tip pointing directly into the gas stream. The pump was started immediately and the flow was adjusted to isokinetic sampling conditions. After the required time interval had elapsed, the probe was repositioned to the next traverse point and isokinetic sampling was re-established. This was performed for each point until the run was completed. Readings were taken at each point and recorded on the field data sheet. At the conclusion of each run, the pump was turned off, final readings were recorded, and final system leak checks were performed.

6.1. Particulate Sample Recovery

Care was exercised in moving the collection train to the sample recovery area to minimize the loss of collected sample, or the gain of extraneous particulate matter. The volume of water in the impingers was measured; the silica gel impinger was weighed and recorded on the field data sheet. The nozzle and all sample-exposed surfaces were washed with reagent grade acetone into a clean sample container. A brush was used to loosen any adhering particulate matter and subsequent washings were placed into the container. The filter was carefully removed from the fritted support and placed in a clean separate sample container. A sample of the acetone used in the washing was saved for a blank laboratory analysis.

6.2. Particulate Analytical Procedures

The filter and any loose particulate matter were transferred from the sample container to a clean, tared weighing dish. The filter was placed in a desiccator for at least 24 hours and then weighed to the nearest 0.1 milligram until a constant weight was obtained. The original weight of the filter was deducted, and the weight gain was recorded to the nearest 0.1 milligram.

The wash solution was transferred to a clean, tared beaker. The solution was evaporated to dryness, desiccated to a constant weight, and the weight gain was recorded to the nearest 0.1 milligram.

7. QUALITY ASSURANCE

In order to ensure the accuracy of all the data collected in the field and at the laboratory, SEAS has instituted a comprehensive quality assurance and quality control program. New or repaired items requiring calibration are calibrated before their initial use in the field. Equipment with calibration that may change with use is calibrated before and after each use. When an item is found to be out of calibration, the unit is either discarded or repaired, and then recalibrated before being returned to service. All equipment is periodically recalibrated in full regardless of the results of the regular inspections or its present calibration status. Calibrations are performed in a manner consistent with the EPA reference methods recommended in the "Quality Assurance Handbook for Air Pollution Measurement Systems" published by the US Environmental Protection Agency. To the maximum degree possible all calibrations are traceable to the National Institute of Standards & Technology (NIST).

In order to ensure that the test will be performed in a timely manner without undue delays, SEAS sampling vans are equipped with duplicate sampling devices for almost every device needed to perform the test. If a particular device is broken or does not pass inspection, a second device is available immediately at the site to continue the testing procedures. Any device that appears to be outside calibration or in need of repair is tagged in the field and repaired, calibrated, or discarded immediately upon return to the laboratory.

7.1. Calibrations

Certain pieces of equipment need to be calibrated before and after each test. Those items include the pitot tubes, the differential pressure gauges, the dry gas meter, and the nozzles used for the particulate testing. The following is a brief description of the calibration procedures for each of these important devices.

7.1.1. *Pitot Tubes*

All pitot tubes are the S-type as required by EPA Reference Method 2 (40 CFR, Part 60, Appendix A, Method 2). This method contains certain geometric standards for the construction of S-type pitot tubes. All of SEAS pitot tubes are constructed according to these standards. According to the EPA any pitot tube constructed to these standards will have a coefficient of 0.84 ± 0.02. To ensure the exact value of SEAS pitot tubes, all pitot tubes are initially calibrated in SEAS wind tunnel to determine the exact pitot coefficient. This coefficient should not change unless the pitot is physically damaged. Each pitot tube is checked before going to the field to make sure it meets the geometry as specified. Any pitot tube that does not meet the specifications is not used in the test.

7.1.2. *Differential Pressure Gauges*

SEAS uses several different types of pressure gauges including oil tube manometers, water tube manometers, magnehelics, and current output electronic load cells. Each of these devices are inspected before taken to the field and are inspected for leaks during each test. The magnehelics and load cells are tested against an incline manometer water gauge to ensure accuracy.

7.1.3. *Temperature Sensors*

All temperature sensors used in SEAS sampling program are either mercury in-glass thermometers or type K thermocouples. These thermocouples are physical devices which produce a voltage proportional to the temperature. The thermocouple reading device is calibrated before and after each series of tests to ensure accuracy of $\pm$ 2 percent. The calibration of the thermocouple is accomplished by using a NIST traceable calibrated reference thermocouple potentiometer system.

7.1.4. *Nozzles*

The inside diameter of each nozzle is measured to the nearest 0.001 inches prior to its initial use. Upon arriving in the field each nozzle is again measured with a micrometer on three different points on the diameter to ensure its original measurement and that the nozzle is perfectly round. If the difference between the maximum and minimum diameters measured does not exceed 0.003 inches, the nozzle is acceptable; otherwise, this nozzle is discarded and another is selected. At the end of each test the nozzles are again measured on three different points on the diameter to ensure that during the test the nozzle has not become dented or deformed.

7.1.5. *Dry Gas Meter*

The dry gas meter is calibrated every six months against a spirometer transfer standard. It is again calibrated before and after each use in the field. During the semiannual calibration, a five point calibration is made at a minimum of one-half inch water column orifice pressure up to four inches water column orifice pressure. Before and after each test, the dry gas meter is again recalibrated at three repetitions at a representative flow rate experienced during the test. If the final calibration does not agree with the initial calibration within five percent the calibration that yields the lowest volume of sample pulled is used in the calculation of results and the dry gas meter is repaired and recalibrated.

7.1.6. *Orifice*

The flow meter orifice is used to establish isokinetic sampling rates during the test. The orifice is calibrated in conjunction with the calibration of the dry gas meter. The orifice is calibrated over a wide range of flow rates and the arithmetic mean of the orifice calibration is used for sampling purposes. The orifice is recalibrated every time the gas meter is recertified.

APPENDIX A QUALITY CONTROL OF PARTICULATE TESTING EQUIPMENT

INITIAL METER BOX CALIBRATION

Calibrated By: KDO **BOX #:** S-100 **Date:** 4/21/2004

		Orifice #:	1	Orifice #:	3	Orifice #:	8	Reference Meter #	Unit	RUN 4	RUN 5	
	Unit	RUN 1	RUN 2	RUN 1	RUN 2	RUN 1	RUN 2	Field Meter DH	In. H_2O	4.00	5.00	
Meter ΔH	In. H_2O	0.74	0.75	1.26	1.27	1.47	1.46	*Initial* Gas Volume	$Ft.^3$	64.200	78.600	
Initial Gas Volume	$Ft.^3$	35.400	88.900	52.200	97.400	45.000	104.300	*Final* Gas Volume	$Ft.^3$	74.390	88.600	
Final Gas Volume	$Ft.^3$	43.400	96.900	58.000	103.400	51.000	112.200	*Initial* Temp. Out	°F	75	76	
Initial Temp. Out	°F	75	76	74	77	75	77	*Final* Temp. Out	°F	75	76	
Final Temp. Out	°F	75	77	77	77	75	77	Reference Me Y	*Dimensionless*	1.000	1.000	
Vacuum	In. Hg	20	20	19	19	18	18	*Initial* Gas Volume	$Ft.^3$	258.180	270.740	
Ambient Temp.	°F	75	75	75	75	75	75	*Final* Gas Volume	$Ft.^3$	268.550	281.000	
Barometric Pressure	In. Hg	30.21	30.21	30.21	30.21	30.21	30.21	*Initial* Temp.	°F	75	76	
Time	sec	1019	1020	575	592	551	731	*Final* Temp.	°F	75	76	
K'		0.3632	0.3632	0.4654	0.4654	0.5052	0.5052	Barometric Pressure	In. Hg	30.21	30.21	
CALCULATIONS								Time	sec	572	510	
Total Meter Gas Volume	Actual $Ft.^3$	8.000	8.000	5.800	6.000	6.000	7.900					
Time	Minutes	16.983	17.000	9.583	9.867	9.183	12.183					
Volume through the Meter	*SDCF without Y*	7.983	7.961	5.790	5.973	5.998	7.868					
Volume through the Orifice	*SDCF*	8.056	8.064	5.825	5.998	6.060	8.039					
Calculated Y	*Dimensionless*	1.009	1.013	1.006	1.004	1.010	1.022			1.008	1.014	**1.011**
Difference	*Allowable 0.02*	-0.002	0.002	-0.005	-0.007	0.000	0.011			-0.003	0.003	
Calculated DH@		1.798	1.816	1.858	1.872	1.846	1.827			1.898	1.930	**1.856**
Difference	*Allowable 0.2*	-0.057	-0.040	0.002	0.017	-0.009	-0.029			0.042	0.075	

Magnehelic Calibrations

Device	Calibration	Delta P	
	Standard	Magnehelic	
Units	inches water	inches water	*Percent*
Reading	Reference	Sample	*Error*
1	0.45	0.44	*-2.2*
2	0.73	0.73	*0.0*
3	1.00	1.00	*0.0*

Allowed Error = 5% of Reading

Thermocouple Calibrations

Device	Calibration	Thermocouple	
	Standard	Detector	
Units	Degrees F.	Degrees F.	*Percent*
Reading	Reference	Sample	*Error*
1	100	98	*-0.4*
2	300	301	*0.1*
3	500	499	*-0.1*

Allowed Error = 1.5% of Absolute Temperature (Degrees Rankin);
Absolute Temperature = Temperature in Degrees Fahrenheit. + 460

Final Meter Box Calibration Check by Critical Orifice

Calibrated By: JCS   Date 6/18/2004   METER BOX #: S-100

		Units	Orifice # 8 RUN 1	RUN 2	RUN 3		
Meter	ΔH	In. H_2O	1.49	1.49	1.49		
	Initial **Gas Volume**	Ft.^{3}	558.600	566.700	575.300		
	Final **Gas Volume**	Ft.^{3}	566.600	575.200	584.100		
	Initial **Temp. Out**	°F	72	72	72		
	Final **Temp. Out**	°F	72	72	73		
Vacuum (must be > 16.0)		In. Hg	19	19	19		
	Ambient **Temp.**	°F	72	72	72		
	Barometric Pressure	In. Hg	30.08	30.08	30.08		
	Time	sec	750	792	818		
	K'		0.5052	0.5052	0.5052		
CALCULATIONS							
Total Meter Gas Volume		Ft.^{3}	8.000	8.500	8.800		
	Time	Minutes	12.500	13.200	13.633		
Vm = Volume through the Meter		*SDCF without Y*	8.008	8.509	8.801	**Final**	**Initial**
Vcr = Volume through the Orifice		*SDCF*	8.236	8.697	8.982	**Average**	**Average**
	Calculated Y	*Dimensionless*	**1.028**	**1.022**	**1.021**	**1.024**	**1.011**
	Calculated $\Delta H@$		**1.896**	**1.896**	**1.892**	**1.894**	**1.856**

Magnehelic Calibrations

Device	Calibration	Delta P	
	Standard	Magnehelic	
Units	inches water	inches water	*Percent*
Reading	Reference	Sample	*Error*
1	0.50	0.50	*0.0*
2	1.50	1.49	*-0.7*
3	1.95	1.94	*-0.5*

Allowed Error = 5% of Reading

Thermocouple Calibrations

Device	Calibration	Thermocouple	
	Standard	Detector	
Units	Degrees F.	Degrees F.	*Percent*
Reading	Reference	Sample	*Error*
1	100	100	*0.0*
2	300	299	*-0.1*
3	500	501	*0.1*

Allowed Error = 1.5% of Absolute Temperature (Degrees Rankin);
Absolute Temperature = Temperature in Degrees Fahrenheit. + 460

Magnehelic Calibration

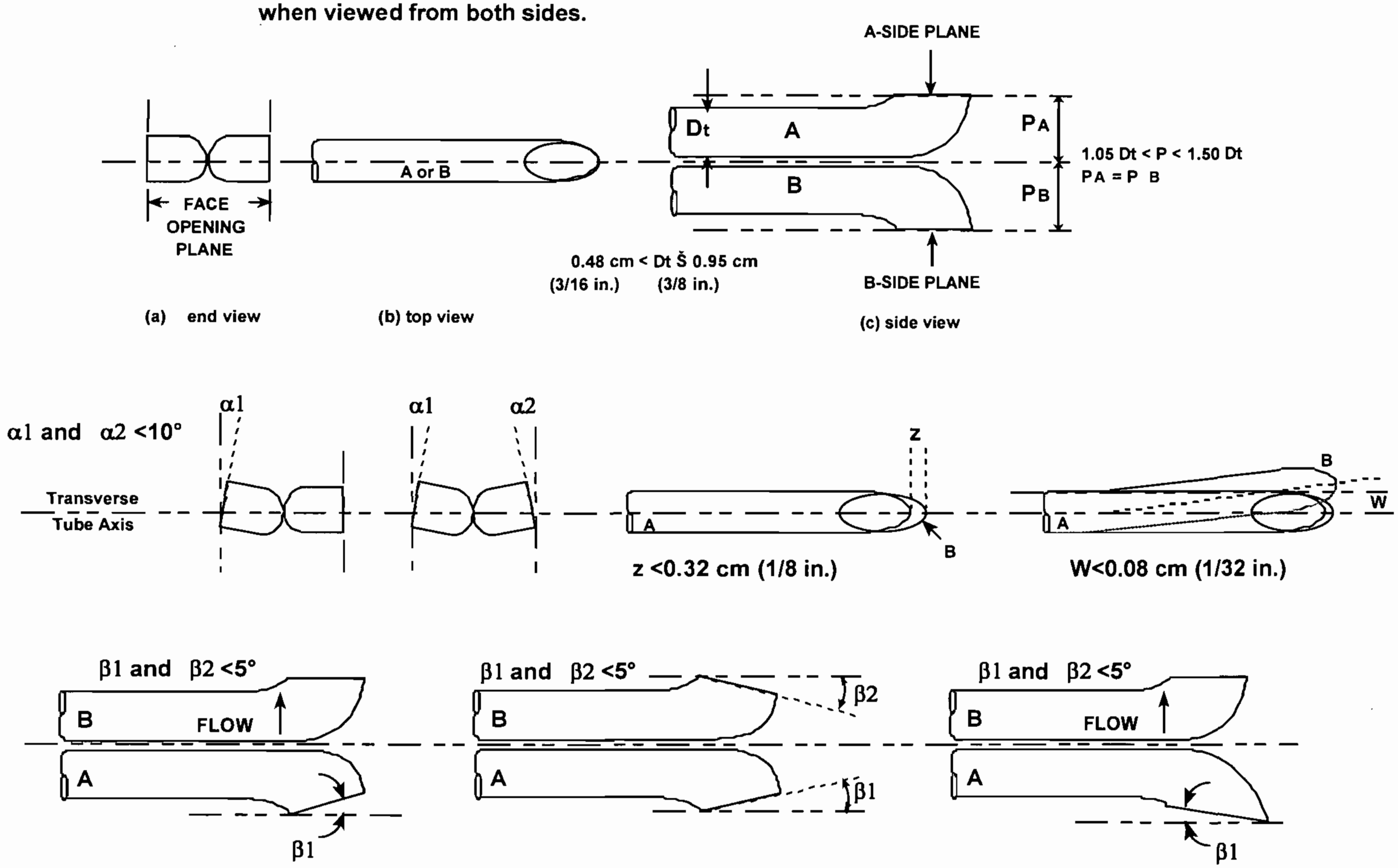
	Box 100						Box 101							Box 100-a				
Ser. No.	**WO21 JY**	**R10908 AG71**	**R98073 14022**	**R977110 5290**	**R96091 6AG447**	**R970227 GJ31**	**R006301 YR66**	**R22D**	**A980821 7883**	**R90051 6G721**	**R981202 CA55**	**R901015 D102**		**R08F2**	**R97020 3**	**R10629J A82**	**R10513 MR42**	**R90124R I119**
Span (in H2O)	**0.25**	**0.5**	**2**	**5**	**10**	**25**	**0.25**	**0.5**	**2**	**5**	**10**	**25**		**0.5**	**2**	**5**	**10**	**25**
Reference Reading @ 0% Span (in H2O)	0.000	0.000	0.00	0.00	0.00	0.00	0.000	0.00	0.00	0.000	0.00	0.00		0.00	0.00	0.00	0.00	0.00
Device Reading (in H2O)	0.000	0.000	0.00	0.00	0.00	0.00	0.000	0.00	0.00	0.000	0.00	0.00		0.00	0.00	0.00	0.00	0.00
% Difference (Allowed = 0.05)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00
Reference Reading @ 50% Span (in H2O)	0.125	0.250	1.00	2.45	5.00	12.50	0.125	0.25	1.00	2.500	4.80	12.50		0.25	1.00	2.50	5.00	13.00
Device Reading (in H2O)	0.125	0.250	1.00	2.50	5.00	12.50	0.125	0.25	0.96	2.500	5.00	12.55		0.25	1.00	2.50	5.00	13.00
% Difference (Allowed = 0.05)	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.04	0.00	0.04	0.00		0.00	0.00	0.00	0.00	0.00
Reference Reading @ 90% Span (in H2O)	0.225	0.45	1.80	4.45	9.00	22.50	0.24	0.44	1.80	4.50	9.00	24.00		0.45	1.80	4.50	9.00	24.00
Device Reading (in H2O)	0.225	0.450	1.80	4.45	9.00	22.50	0.240	0.45	1.80	4.500	9.20	24.00		0.45	1.80	4.50	9.00	24.00
% Difference (Allowed = 0.05)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.02	0.00		0.00	0.00	0.00	0.00	0.00

	Box 102						Box 103					
Ser. No.	**10819 DR2**	**R10902 AG18**	**R50315 EB93**	**810629T A87**		**R10722 MC5**	**R05E**	**R980402 CA34**	**R20202C F1**	**WOBK JM**	**R360**	
Span (in H2O)	**0.25**	**0.5**	**2**	**5**		**25**	**0.25**	**0.5**	**1**	**2**	**5**	**25**
Reference Reading @ 0% Span (in H2O)	0.000	0.000	0.00	0.00		0.00	0.000	0.000	0.00	0.00	0.00	0.00
Device Reading (in H2O)	0.000	0.000	0.00	0.00		0.00	0.000	0.000	0.00	0.00	0.00	0.00
% Difference (Allowed = 0.05)	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reference Reading @ 50% Span (in H2O)	0.130	0.250	1.00	2.40		12.80	0.125	0.245	0.50	1.00	2.40	12.50
Device Reading (in H2O)	0.125	0.255	1.02	2.50		12.50	0.121	0.250	0.50	1.03	2.50	13.00
% Difference (Allowed = 0.05)	0.04	0.02	0.02	0.04		0.02	0.03	0.02	0.00	0.03	0.04	0.04
Reference Reading @ 90% Span (in H2O)	0.240	0.490	1.90	4.70		24.20	0.235	0.440	0.90	1.90	4.90	24.00
Device Reading (in H2O)	0.240	0.490	1.90	4.75		24.00	0.230	0.450	0.90	1.90	5.00	24.00
% Difference (Allowed = 0.05)	0.00	0.00	0.00	0.01		0.01	0.02	0.02	0.00	0.00	0.02	0.00

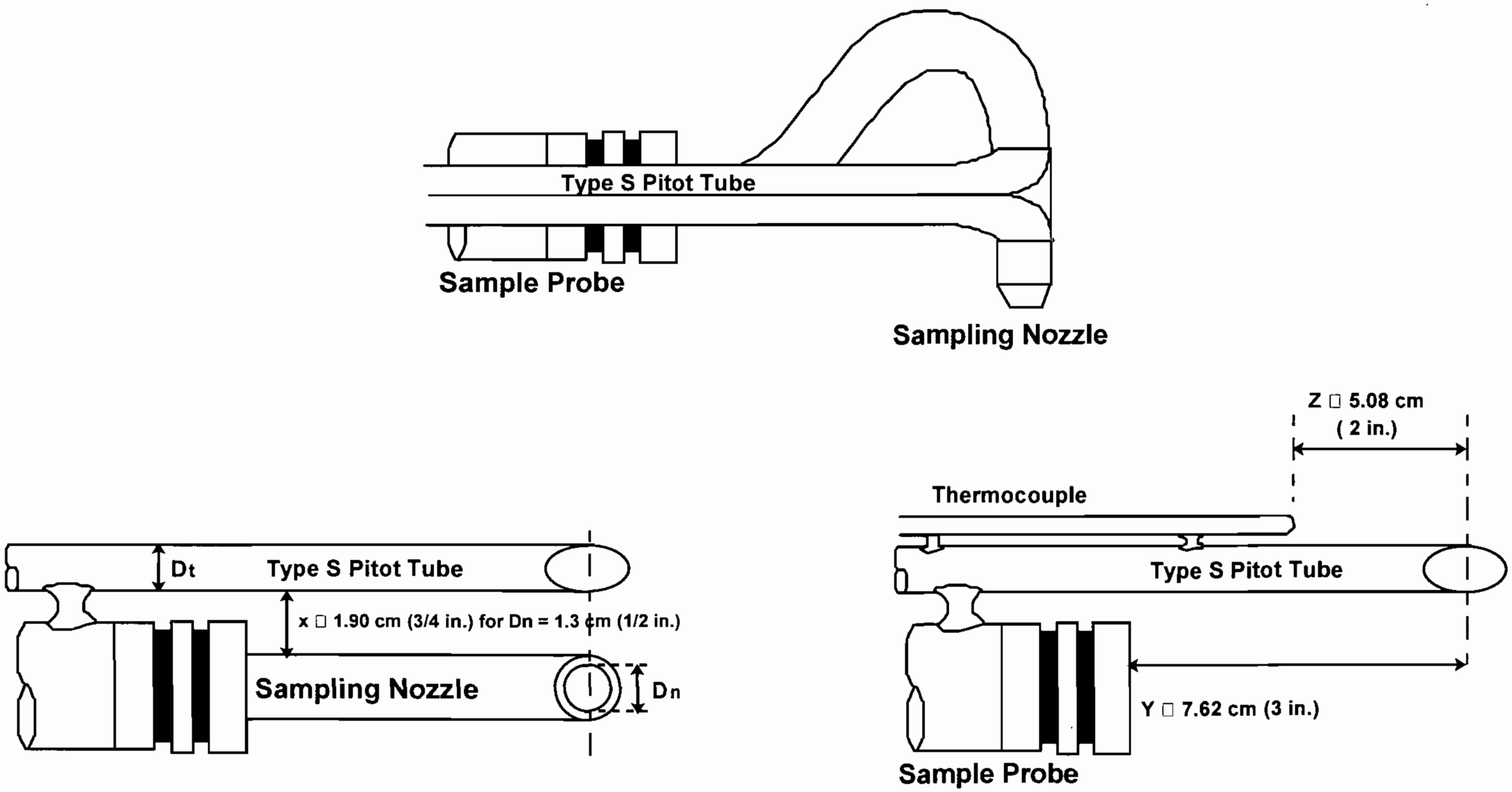
Cailbration Date 06-17-02 By J. RAMPULLA

Type S pitot tube construction details:

a) end view; face opening planes perpendicular to transverse axis.
b) top view; face opening planes parallel to longitudinal axis.
c) side view; both legs of equal length and centerlines coincident, when viewed from both sides.



Sampling Nozzle, Thermocouple, and Probe Configuration



APPENDIX B FIELD DATA SHEETS FOR PARTICULATE TESTING

Sanders Engineering & Analytical Services, Inc.

1568 Leroy Stevens Rd.
Mobile, Al. 36695

Office: (251) 633-4120
Fax: (251) 633-2285

COMPANY Gulf Power Company DATE 6-17-04 DGM# 5-100
PLANT Crist OPERATOR RSR ΔHa
UNIT 7 CAM 1 METHOD 17 PROBE (Max Length Allowed)

	Run 1 CAM	Run 2 CAM	Run 3 CAM
Nozzle Calibration Pre / Post	.190 / .190; .190 / .190; .190 / .190	.190 / .190; .190 / .190; .190 / .190	.190 / .190; .190 / .190; .190 / .190
Average	.190	.190	.190
Filter Number	3470	3473	3471
Meter Reading Final	474.200	513.190	551.230
Initial	439.410	474.800	513.950
Net	34.790	38.390	37.280
Leak Check System Pre (in. Hg / cfm)	15 / .000	15 / .000	15 / .015
Leak Check System Post (in. Hg / cfm)	15 / .000	15 / .000	15 / .015
Pitot Pre (Impact / Static)	✓ / ✓	✓ / ✓	✓ / ✓
Pitot Post (Impact / Static)	✓ / ✓	✓ / ✓	✓ / ✓

VOLUME OF LIQUID WATER COLLECTED

Run		Imp 1	Imp 2	Imp 3	Imp 4
1	Final	158	0	0	1845
1	Initial	100	0	0	1834
1	Net	58	0	0	11
1	Total	69			
2	Final	167	0	0	1856
2	Initial	100	0	0	1845
2	Net	67	0	0	11
2	Total	78			
3	Final	174	0	0	1867
3	Initial	100	0	0	1856
3	Net	74	0	0	11
3	Total	85			

	Run 1	Run 2	Run 3
GAS ANALYSIS O_2	6.3	6.5	6.8
CO_2	13.5	14.0	14.0
CO	/	/	/
STATIC (in. H_2O)	1.5	1.5	1.5
BAROMETRIC (in. Hg)	30.10	30.10	30.10

Form Revised 8/24/02

Page 1 of

Port # / Point#	Time	Gas Meter Volume (Cubic Feet)	Velocity Head ΔP (In. H_2O)	Orifice Head ΔH (In. H_2O)	Temperature °F Stack	Filter	Imp.	Gas Meter	Vac. (In. Hg)
1-1	13:58	439.410	2.24	2.01	337		61	91	8
2	14:00	440.7	2.04	1.83	324		61	91	8
3	14:02	442.3	1.90	1.70	323		61	91	8
4	14:04	443.8	1.28	1.14	326		61	92	6
5	14:06	445.0	1.66	1.49	334		61	92	7
6	14:08	446.1	2.07	1.85	346		61	92	8
2-1	14:12	447.6	1.10	.98	340		61	92	8
2	14:14	448.6	.93	.83	329		61	92	5
3	14:16	449.7	1.09	.97	324		61	92	5
4	14:18	450.7	1.29	1.58	326		61	92	9
5	14:20	451.9	1.58	1.41	335		61	92	9
6	14:22	453.3	1.36	1.22	344		61	92	9
3-1	14:23	454.5	1.21	1.08	340		61	92	6
2	14:25	455.7	1.17	1.05	340		61	92	7
3	14:27	456.6	1.37	1.23	325		61	94	8
4	14:29	457.7	1.01	.907	326		61	94	8
5	14:31	458.9	1.38	1.23	333		61	94	8
6	14:33	459.9	1.01	.90	341		61	94	8
4-1	14:38	469.9	2.84	2.55	342		61	94	9
2	14:40	462.6	.95	.85	326		61	95	8
3	14:42	463.8	1.35	1.21	326		61	95	9
4	14:44	464.8	1.11	.99	327		61	95	9
5	14:46	466.1	1.35	1.12	328		61	95	10
6	14:48	467.3	1.24	1.11	290		61	95	10
5-1	14:52	468.3	1.10	.98	341		61	95	10
2	14:54	469.4	.67	.60	328		61	95	10
3	14:56	470.4	.81	.72	326		61	96	10
4	14:58	471.3	.85	.76	328		61	96	10
5	15:00	472.1	1.10	.98	318		61	96	11
6	15:02	473.1	.60	.53	335		61	96	12
	15:04	474.200							
	:								
	:								

Form Revised 8/24/02

Company: Gulf Power Company Date: 6-17-04 Page ______

Site: #7 Run #: 1 CAM 1 Of ______

Port # / Point#	Time	Gas Meter Volume (Cubic Feet)	Velocity Head ΔP (In. H_2O)	Orifice Head ΔH (In. H_2O)	Temperature °F Stack	Filter	Imp.	Gas Meter	Vac. (In. Hg)
1-1	16:32	474.800	2.32	2.08	339		60	94	10
2	:34	476.2	2.28	2.04	334		60	94	10
3	:36	477.8	1.90	1.70	326		60	94	10
4	:38	479.2	1.36	1.22	331		60	94	9
5	:40	480.6	1.97	1.76	336		60	94	10
6	:42	482.0	2.41	2.16	320		60	94	11
2-1	16:46	483.5	1.20	1.07	341		60	93	8
2	:48	484.7	1.13	1.01	332		60	93	8
3	:50	485.7	1.33	1.19	326		60	93	9
4	:52	486.9	1.52	1.36	329		60	93	10
5	:54	488.2	1.67	1.49	335		60	94	11
6	56	489.5	1.55	1.39	341		60	94	11
3-1	16:58	490.8	1.10	.98	342		60	94	8
2	17:00	491.9	1.67	1.49	328		60	94	10
3	:02	493.4	1.96	1.76	327		60	94	10
4	:04	495.2	2.04	1.83	328		60	94	12
5	:06	496.5	1.90	1.70	325		60	94	12
6	:08	497.7	1.70	1.52	325		60	94	12
4-1	17:14	498.6	3.08	2.96	342		60	94	12
2	:16	500.1	1.20	1.07	328		60	94	12
3	:18	501.5	1.61	1.44	326		60	94	12
4	:20	502.5	1.01	.90	326		60	94	12
5	:22	503.7	1.47	1.32	335		60	94	12
6	:24	504.9	1.28	1.14	340		60	94	12
5-1	17:28	506.2	1.22	1.10	342		60	94	13
2	:30	507.5	.97	.87	329		60	94	13
3	:32	508.5	.95	.85	326		60	94	13
4	:34	510.0	1.0	.89	326		60	94	10
5	:36	511.2	1.10	.98	335		60	94	10
6	:38	512.0	1.06	.96	335		60	94	10
	17:40	513.190							
	:	38.390							
	:		1.2359						

Form Revised 8/24/02

Company: Gulf Power Company Date: 6-17-04 Page ____

Site: #7 Run #: 2 CAM 1 Of ____

Port # / Point#	Time	Gas Meter Volume (Cubic Feet)	Velocity Head ΔP (In. H_2O)	Orifice Head ΔH (In. H_2O)	Temperature °F Stack	Filter	Imp.	Gas Meter	Vac. (In. Hg)
1-1	17:52	513.950	.46	.41	337		61	97	3
2	17:54	514.8	2.15	1.93	332		61	97	5
3	17:56	516.0	1.88	1.68	327		61	97	6
4	17:58	517.4	1.41	1.26	329		61	97	6
5	18:00	518.6	2.02	1.81	337		61	97	6
6	18:02	519.9	2.35	2.11	323		61	97	8
2-1	18:04	521.3	1.94	1.74	332		61	97	8
2	18:06	522.9	1.88	1.68	320		61	96	9
3	18:08	524.3	1.69	1.51	327		61	96	9
4	18:10	525.5	1.69	1.51	333		61	96	9
5	18:12	526.9	1.98	1.77	337		62	97	9
6	18:14	528.3	1.78	1.59	342		62	97	9
3-1	18:18	529.6	1.57	1.40	343		62	97	9
2	18:20	531.0	1.70	1.52	328		62	97	9
3	18:22	532.2	1.70	1.52	328		62	97	9
4	18:24	533.7	1.66	1.49	328		62	97	9
5	18:26	534.9	1.70	1.52	328		62	97	9
6	18:28	536.2	1.23	1.10	329		62	97	9
4-1	18:32	537.3	3.19	2.86	343		62	97	10
2	18:34	538.8	1.17	1.05	329		62	97	11
3	18:36	539.8	1.74	1.56	327		62	97	11
4	18:38	541.0	.64	.57	330		62	96	11
5	18:40	542.2	1.50	1.34	334		62	96	11
6	18:42	543.5	1.40	1.25	333		62	96	11
5-1	18:46	544.8	1.14	1.02	343		61	96	11
2	18:48	546.0	1.12	1.00	330		61	96	11
3	18:50	547.1	1.15	1.03	327		61	96	11
4	18:52	548.1	.75	.67	330		61	96	11
5	18:54	549.3	1.0	.89	320		61	96	11
6	18:56	550.2	1.22	1.09	333		61	96	11
	18:58	551.230							
	:								
	:								

Form Revised 8/24/02

Company: Gulf Power Company Date: 6-17-04 Page ____

Site: #7 Run #: 3 CAM 1 Of ____

LABORATORY ANALYSIS & CHAIN OF CUSTODY

COMPANY/PLANT: GPCO Crist 7 CAM Condition 1

UNIT #: 7 CAM 1 DATE OF TEST: 6-17-04 TYPE OF TEST: ☐ M-5 ☒ M-17 ☐ OTHER ______

SAMPLE #	RELINQUISHED BY:	RECEIVED BY:	TIME:	DATE:	REASON FOR CHANGE
3470	JDR	Jcw	0800	6-18-04	Analysis
3473					
3471					

RUN # 1	FILTER # 3470	BEAKER 16 WASH (ML)	RUN #	FILTER #	BEAKER WASH (ML)
FINAL WEIGHT	168.3	67860	FINAL WEIGHT		
INITIAL WEIGHT	115.3	67856	INITIAL WEIGHT		
DIFFERENCE	53.0	4.0	DIFFERENCE		
	CORRECTED TOTAL WEIGHT	57.0		CORRECTED TOTAL WEIGHT	
RUN # 2	FILTER # 3473	BEAKER 6 WASH (ML)	RUN #	FILTER #	BEAKER WASH (ML)
FINAL WEIGHT	188.3	62734.7	FINAL WEIGHT		
INITIAL WEIGHT	116.8	62730.7	INITIAL WEIGHT		
DIFFERENCE	71.5	4.0	DIFFERENCE		
	CORRECTED TOTAL WEIGHT	75.5		CORRECTED TOTAL WEIGHT	
RUN # 3	FILTER # 3471	BEAKER 35 WASH (ML)	RUN #	FILTER #	BEAKER WASH (ML)
FINAL WEIGHT	161.6	63794.5	FINAL WEIGHT		
INITIAL WEIGHT	121.4	63787.8	INITIAL WEIGHT		
DIFFERENCE	40.2	6.7	DIFFERENCE		
	CORRECTED TOTAL WEIGHT	46.9		CORRECTED TOTAL WEIGHT	

WASH SOLVENT BLANK (ML)		BEAKER # WASH (ML)
FINAL WEIGHT		
INITIAL WEIGHT		
DIFFERENCE		
CORRECTED TOTAL WEIGHT		

APPENDIX C SAMPLE CALCULATIONS

Sample Calculations, Run 1
GULF POWER COMPANY
PLANT CRIST, UNIT 7
CAM CONDITION 1

Absolute Stack Pressure (inches Mercury)

$$P_S = P_{bar} + \frac{\overline{P_g}}{13.6}$$

P_g = Stack Static Pressure (inches Water) =	1.50
P_{bar} = Barometric Pressure (inches Mercury) =	30.10
P_s =	30.21

Absolute Pressure at the Dry Gas Meter (inches Mercury)

$$P_m = P_{bar} + \frac{\overline{\Delta H}}{13.6}$$

P_{bar} = Barometric Pressure (inches Mercury) =	30.10
ΔH = Average pressure difference of orifice (inches Water) =	1.19
P_m =	30.19

Average Stack Gas Velocity (feet per second)

$$V_s = K_p C_p \overline{\sqrt{\Delta P}} \sqrt{\frac{\overline{T_s}}{M_s P_s}}$$

Kp = Pitot tube constant $\sqrt{\frac{(\text{lb/lb - mole})\ (\text{inches Hg})}{(^\circ\text{R})\ (\text{inches H2O})}}$ =	85.49
C_p = Pitot tube coefficient (dimensionless) =	0.84
$\overline{\sqrt{\Delta P}}$ = Velocity head of stack gas (inches H2O) =	1.1312
Ts = Average absolute temperature of stack, degrees Rankin =	789.9
M_s = Molecular weight of stack gas; wet basis (lb/lb mole) =	29.33
P_s = Absolute stack pressure (inches Mercury) =	30.21
V_s =	76.70

Volume of Gas Sampled Measured by Dry Gas Meter

(corrected to standard conditions, SDCF)

$$Vm(Std) = K_1 V_m Y \left[\frac{P_{bar} + \frac{\Delta H}{13.6}}{T_m} \right]$$

K_1 = Degrees R/inches Mercury =	17.64
V_m = Volume of gas sample as measured by dry gas meter (actual cubic feet) =	34.790
Y = Dry gas meter calibration factor (dimensionless) =	1.011
P_{bar} = Barometric Pressure (inches Mercury) =	30.10
Δ H = Average pressure difference of orifice (inches H2O) =	1.19
Ts = Average absolute temperature of the dry gas, degrees Rankin =	553.1
$V_{m\,(Std)}$ =	33.861

Volume of Water Vapor in Gas Sample

(corrected to standard conditions, SDCF)

$$V_{w\,(Std)} = 0.04707\ V_{lc}$$

V_{lc} = Total volume of liquid collected in impingers and silica gel (milliliters) =	69.0
$V_{w\,(Std)}$ =	3.248

Water Vapor in the Gas Stream proportion by volume (dimensionless)

$$B_{ws} = \frac{V_{w(Std)}}{V_{m(Std)} + V_{w(Std)}}$$

$V_{w\,(std)}$ = Volume of water in gas sample (corrected to standard conditions) =	3.248
$V_{m(std)}$ = Volume of sample measured by dry gas meter (standard conditions) =	33.861
B_{ws} =	0.088

Molecular Weight of Stack Gas (dry basis, lb/lb mole)

$$M_d = 0.44(\%CO_2) + 0.32(\%O_2) + 0.28(\%N_2 + \%CO)$$

$\%CO_2$ = Number percent by volume (dry basis from gas analysis) =	13.50
$\%O_2$ = Number percent by volume (dry basis from gas analysis) =	6.30
$\%N_2$+%CO = Number percent by volume (dry basis from gas analysis) =	80.20
M_d =	30.41

Molecular Weight of Stack Gas (wet basis, lb/lb mole)

$$M_s = M_d(1 - B_{ws}) + 18(B_{ws})$$

M_d = Molecular weight of stack gas (dry basis, lb/lb mole) =	30.41
B_{ws} = Water vapor in the gas stream (proportion by volume, dimensionless) =	0.088
M_s =	29.33

Volumetric Flow Rate (actual cubic feet per minute)

$$Q_a = (V_s)(A_s)(60)$$

V_s = Average stack gas velocity (feet per second) =	76.70
A_s = Cross sectional area of stack (feet squared) =	366.263
Q_a =	1,037,385

Volumetric Flow Rate (standard dry cubic feet per minute)

$$Q_s = Q_a(1 - B_{ws}) \frac{(528)}{\overline{T_s}} \frac{(P_s)}{29.92}$$

Q_a = Volumetric flow rate (actual cubic feet per minute) =	1,037,385
B_{ws} = Water vapor in the gas stream (proportion by volume, dimensionless) =	0.088
Ts = Average absolute temperature of stack, degrees Rankin =	789.9
P_s = Absolute stack pressure (inches Mercury) =	30.21
Q_s =	1,685,597

Volumetric Flow Rate (standard wet cubic feet per minute)

$$Q_{sw} = Q_a \frac{(528)}{\overline{T_s}} \frac{(P_s)}{29.92}$$

Q_a = Volumetric flow rate (actual cubic feet per minute) =	1,037,385
Ts = Average absolute temperature of stack, degrees Rankin =	789.9
P_s = Absolute stack pressure (inches Mercury) =	30.21
Q_{sw} =	1,136,887

Particulate Mass Rate (pounds per hour)

$$PMR = (Cs)\,(Qs)\,\frac{(60)}{7000}$$

Cs =Polutant concentration (grains per standard dry cubic foot) =	0.0259
Q_a = Volumetric flow rate (standard dry cubic feet per minute) =	1,685,597
PMR =	230.51

Particulate Concentration (grains per standard dry cubic foot)

$$C_s = 0.0154\,\frac{M_n}{V_{m(Std)}}$$

Mn = Total amount ofPolutant collected (milligrams) =	57.0
$V_{m(Std)}$ = Volume of stack gas sampled (corrected to standard conditions) =	33.861
C_s =	0.0259

Particulate Concentration (grains per actual cubic foot)

$$C_a = 0.0154\,\frac{M_n}{V_{n\,(actual)}}$$

Mn = Total amount ofPolutant collected (milligrams) =	57.0
$V_{n\,(actual)}$ = Volume sampled at stack conditions (actual cubic feet) =	55.008
C_a =	0.0160

Percent of Isokinetic Sampling

$$I = \frac{100\ V_n}{(60)\ \varnothing\ V_s\, A_n}$$

V_n = Volume sampled at stack conditions through nozzle (actual cubic feet) =	55.008
V_s = Average stack gas velocity (feet per second) =	76.70
A_n = Cross-sectional area of nozzle (feet squared) =	0.000197
$\varnothing$ = Sampling Time (minutes) =	60
I =	101.2

Volume of Gas Sampled Through Nozzle (actual cubic feet)

$$V_n = \left[(0.002669)(V_{lc}) + Y\frac{V_m}{T_m}\left(P_{bar} + \frac{\overline{\Delta H}}{13.6}\right)\right]\frac{\overline{T_s}}{P_s}$$

V_{lc} = Total volume of liquid collected in impingers and silica gel (milliliters) =	69.0
Y = Dry gas meter calibration factor (dimensionless) =	1.011
V_m = Volume of gas sample as measured by dry gas meter (actual cubic feet) =	34.790
Tm = Average absolute temperature of dry gas meter, degrees Rankin =	553.1
P_{bar} = Barometric Pressure (inches Mercury) =	30.10
ΔH = Average pressure difference of orifice (inches Water) =	1.19
Ts = Average absolute temperature of stack, degrees Rankin =	789.9
P_s = Absolute stack pressure (inches Mercury) =	30.21
V_n =	55.008

Emission Rate in Pounds Per Million Btu (EPA Oxygen F Factor)

$$E = C_d F_{O2}\left(\frac{20.9}{20.9 - \%O_2}\right)$$

Cd = Pollutant concentration (pounds per standard dry cubic foot) =	0.0000037
F_{O2} = Oxygen based F factor (SDCF/mmBtu for bituminous coal) =	9780
$\%O_2$ = Number percent by volume (dry basis from gas analysis) =	6.3
E_{O2} =	0.0518

Unit Operating Rate-Million Btu per Hour

$$UOR = \left(\frac{PMR}{E_{O2}}\right)$$

E_{O2} = Emission Rate in Pounds Per Million Btu (EPA Oxygen F Factor) =	0.0518
PMR = Pollutant Mass Rate (pounds per hour) =	230.51
UOR=	4446

APPENDIX D OPERATIONAL DATA

Gulf Power Plant Crist Unit 7
CAM Test Notes
CAM Condition 1 Testing 06/17/04

Run #1

Start Time		Notes
CDT	**CEMS**	No operational problems noted.
14:58	13:58	
Stop Time		
CDT	**CEMS**	
16:04	15:04	

Run #2

Start Time		Notes
CDT	**CEMS**	No operational problems noted.
17:32	16:32	
Stop Time		
CDT	**CEMS**	
18:40	17:40	

Run #3

Start Time		Notes
CDT	**CEMS**	No operational problems noted.
18:52	17:52	
Stop Time		
CDT	**CEMS**	
19:58	18:58	

Crist 7 CAM TEST							
Maximum Allowable Heat Input: 6,406.4 mmBtu/hr							
Steady State June 17, 2004							
					coal flow	Coal	LDMS
Run #	Load	Start	End	Duration	from LDMS	Analysis	results
	Gross MW	Time	Time	(Hours)	(tons)	Btu / lb	mmBtu's/hr
1	498.5	13:58	15:04	1.10	218.70	11410	4537.0
2	499.5	16:32	17:40	1.13	223.00	11542	4542.1
3	500	17:52	18:58	1.10	218.40	11651	4626.5
	499					**Average**	4568.6
						Percent of Max Allowable	71%
						Load Limit if % < 90%	549

6406.4

CEMS OPACITY DATA
Crist 7

Date	CEM Hour	Minutes									
		00	6	12	18	24	30	36	42	48	54
		CAM Condition 1									
06/17/04	13										17.8
06/17/04	14	17.2	21.1	17.4	17.6	17.8	18.2	17.4	17.6	17.7	22.2
06/17/04	15	18.6	17.6								
06/17/04	16						18.4	17.4	17.1	17.3	17.3
06/17/04	17	18.1	23.2	19.2	17.5	17.5	17.6	17.8	18.4		24.9
06/17/04	18	18.2	17.9	18.0	18.5	18.6	19.1	21.1	18.8	18.5	18.7

GULF POWER
A SOUTHERN COMPANY

Crist Plant Particulate Compliance Test Control Room Data

GULF POWER
A SOUTHERN COMPANY

Unit: 7 **Date:** JUNE 17, 2004 CAM (CONDITION 1)

Check one: Sootblowing X Steady State (no sootblowing)

Unit Operator: COLBERT

Run	Cems Time	Pulverizer Coal Integrators (x 100 pounds) A	B	C	D	E	F	Generation Digital Meter MW	Gross Generation Integrator MWhr	Main Steam Total Flow (x 10e6 lb/hr)	Boiler Air Flow (x 10e6lb/hr)	Excess 02 A	Excess 02 B	Opacity 6 Min. Avg %	I.D.Fan Amps A / C	I.D.Fan Amps B / D	Gas Temp Air Htr. OutletDeg F A	Gas Temp Air Htr. OutletDeg F B	SH/RH Temp SH	SH/RH Temp RH
#1 Start	1358	660154	471316	415617	664701	666570	428620	498	499	3537	4555	4.1	3.0	17.7	390 / 402	388 / 405	287	305	999	984
#1 End	1604	660196	471357	415656	664729	666612	428662	499	499	3515	4586	4.3	3.0	18.5	388 / 405	388 / 407	288	307	999	984
#2 Start	1632	660252	471414	415709	664767	666669	428719	499	499	3536	4598	4.3	3.1	18.3	388 / 403	390 / 464	286	306	1001	984
#2 End	1740	660299	471460	415753	664798	666715	428765	500	498	3534	4585	4.0	2.9	18.3	389 / 413	389 / 406	286	306	1000	984
#3 Start	1752	660302	471463	415755	664800	666718	428768	500	499	3545	4582	3.9	2.8	18.0	391 / 408	390 / 409	286	306	1000	985
#3 End	1858	660344	471506	415796	664829	666761	428812	500	499	3553	4608	3.9	2.9	18.6	392 / 410	394 / 406	298	307	999	985

Operational Comments

Run #1	
Run #2	
Run #3	

Inside Operator V. COLBERT
Outside Operator (Coal Samples) H. SWILLEY
Laboratory man (Ash Samples) C. FLEMING
Electrician (Esp Readings) T. TOLBERT

GULF POWER
A SOUTHERN COMPANY

Plant Crist
Unit 7
Precipitator Report

CAM Run 1

Precipitator Readings

	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	468	468	468	468	467	466	466	466	466	466
Primary Current	2.8	3.2	2.8	4.0	68.3	2.4	3.2	3.2	3.9	68.0
Total Power	1	1	1	1	24	1	1	1	1	23
Secondary kV	0.0	0.0	0.0	33.3	50.2	0.0	0.0	0.0	37.2	47.7
Secondary mA	3.1	4.9	3.1	19.8	400.0	4.2	4.7	5.0	19.8	399.5
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	468	468	468	468	466	465	465	465	465	464
Primary Current	3.2	3.1	0.2	4.0	68.0	0.0	2.5	0.2	4.2	67.4
Total Power	1	1	0	1	23	0	1	0	1	23
Secondary kV	0.0	0.0	0.0	35.3	50.3	0.0	0.0	0.0	38.6	49.1
Secondary mA	4.1	3.3	4.9	19.8	400.0	2.0	5.0	3.1	19.8	399.8
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	467	467	467	467	467	465	465	464	464	464
Primary Current	0.0	3.2	0.3	4.1	67.2	3.0	0.2	2.8	4.1	68.1
Total Power	0	1	0	1	23	1	0	1	1	23
Secondary kV	0.0	0.0	0.0	34.2	49.9	0.0	0.0	0.0	37.6	48.5
Secondary mA	1.7	4.7	3.3	19.8	400.0	4.9	4.7	3.3	19.8	399.7
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0

GULF POWER
A SOUTHERN COMPANY

Plant Crist
Unit 7
Precipitator Report

CAM Run 1

Precipitator Readings

	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	468	468	468	468	467	467	467	466	467	466
Primary Current	2.8	3.2	2.8	4.1	68.7	2.3	3.2	3.2	3.9	68.2
Total Power	1	1	1	1	24	1	1	1	1	23
Secondary kV	0.0	0.0	0.0	34.5	51.1	0.0	0.0	0.0	37.9	48.4
Secondary mA	3.1	4.9	3.1	19.9	400.0	4.1	4.7	5.0	19.9	400.2
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	468	468	468	468	467	466	466	465	465	465
Primary Current	3.2	3.1	0.2	4.0	68.2	0.0	2.5	0.2	4.3	67.4
Total Power	1	1	0	1	23	0	1	0	1	23
Secondary kV	0.0	0.0	0.0	36.4	51.0	0.0	0.0	0.0	40.2	50.0
Secondary mA	4.0	3.3	4.9	20.0	400.0	2.0	5.0	3.1	19.8	399.7
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	467	467	467	467	467	465	465	465	465	464
Primary Current	0.0	3.2	0.3	4.1	67.4	3.0	0.2	2.8	4.2	68.0
Total Power	0	1	0	1	23	1	0	1	1	22
Secondary kV	0.0	0.0	0.0	34.3	50.2	0.0	0.0	0.0	39.1	49.2
Secondary mA	1.7	4.7	3.3	19.8	399.7	5.0	4.7	3.3	20.0	399.9
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0

GU[redacted]F POWER
A SOUTHERN COMPANY

Date: [redacted]/2004
START Time [redacted] 1632

CAM RUN 2

[redacted] Plant Crist
Unit 7
Precipitator Report

Precipitator Readings

	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	468	468	468	468	467	467	467	467	467	467
Primary Current	2.9	3.2	2.8	4.0	68.5	2.5	3.2	3.2	3.9	68.1
Total Power	1	1	1	1	24	1	1	1	1	23
Secondary kV	0.0	0.0	0.0	34.0	51.2	0.0	0.0	0.0	37.6	49.0
Secondary mA	3.1	4.9	3.1	19.8	399.6	4.1	4.7	5.0	19.8	399.5
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	468	468	468	468	467	467	466	466	466	465
Primary Current	3.2	3.1	0.2	4.0	68.3	0.1	2.4	0.1	4.1	67.5
Total Power	1	1	0	1	24	0	1	0	1	23
Secondary kV	0.0	0.0	0.0	36.4	51.5	0.0	0.0	0.0	37.3	50.3
Secondary mA	3.9	3.2	4.8	19.8	399.8	1.9	5.0	3.1	19.8	399.9
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	467	467	467	466	467	466	466	466	466	465
Primary Current	0.0	3.2	0.3	4.1	67.6	3.0	0.2	2.9	4.1	68.0
Total Power	0	1	0	1	23	1	0	1	1	23
Secondary kV	0.0	0.0	0.0	34.5	50.8	0.0	0.0	0.0	37.5	49.5
Secondary mA	1.6	4.7	3.3	19.9	400.0	5.0	4.7	3.3	19.9	399.6
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0

G[redacted]LF POWER
A SOUTHERN COMPANY

[redacted]Plant Crist
Unit 7
Precipitator Report

CAM Run2

Preciptator Readings										
	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	468	468	468	468	467	466	466	466	466	466
Primary Current	2.8	0.0	2.8	4.2	68.3	2.3	3.2	3.2	3.9	68.2
Total Power	1	1	0	0	24	1	1	1	1	24
Secondary kV	0.0	0.0	0.0	34.8	51.6	0.0	0.0	0.0	37.1	49.3
Secondary mA	3.1	4.9	3.1	19.9	399.6	4.1	4.7	5.0	19.8	399.7
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	468	468	468	468	467	465	465	465	465	464
Primary Current	3.2	3.1	0.2	4.0	68.2	0.0	2.5	0.3	4.1	67.6
Total Power	1	1	0	1	24	0	1	0	1	23
Secondary kV	0.0	0.0	0.0	35.6	51.9	0.0	0.0	0.0	37.9	50.3
Secondary mA	4.0	3.3	4.8	19.8	399.8	2.0	5.0	3.1	19.9	399.9
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	467	467	467	467	467	465	465	464	464	464
Primary Current	0.0	3.2	0.4	4.1	67.7	3.0	0.3	2.8	4.1	68.0
Total Power	0	1	0	1	23	1	0	1	1	23
Secondary kV	0.0	0.0	0.0	34.8	51.1	0.0	0.0	0.0	37.1	49.2
Secondary mA	1.7	4.7	3.3	19.9	400.0	4.9	4.7	3.3	19.8	400.1
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0

G[redacted]LF POWER
A SOUTHERN COMPANY

[redacted]Plant Crist
Unit 7
Precipitator Report

Date: 6/17/2004
START Tim[redacted] 1752

CAM Run 3

Precipitator Readings

	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	468	468	468	468	467	466	466	466	466	466
Primary Current	2.8	3.2	2.8	4.0	68.3	2.3	3.2	3.2	3.9	68.3
Total Power	1	1	1	1	24	1	1	1	1	24
Secondary kV	0.0	0.0	0.0	33.9	51.7	0.0	0.0	0.0	38.2	49.1
Secondary mA	3.1	4.9	3.1	19.9	399.6	4.1	4.7	5.0	19.9	399.9
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	468	468	467	468	467	466	465	465	465	464
Primary Current	3.2	3.1	0.2	4.0	68.1	0.0	2.5	0.3	4.3	67.9
Total Power	1	1	0	1	24	0	1	0	1	23
Secondary kV	0.0	0.0	0.0	35.3	52.1	0.0	0.0	0.0	39.3	50.4
Secondary mA	4.0	3.3	4.9	19.8	399.8	2.0	5.0	3.1	19.8	399.8
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	467	467	467	466	466	465	465	464	465	464
Primary Current	0.0	3.2	0.4	4.1	67.7	3.0	0.3	2.8	4.2	68.1
Total Power	0	1	0	1	24	1	0	1	1	23
Secondary kV	0.0	0.0	0.0	34.4	51.5	0.0	0.0	0.0	38.3	49.7
Secondary mA	1.7	4.7	3.4	19.8	399.9	4.9	4.7	3.3	19.9	399.8
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0

[redacted]LF POWER
A SOUTHERN COMPANY

Plant Crist
Unit 7
Precipitator Report

Date: 6/17/2004
STOP Tim[redacted] 1858
[redacted]1 of 1

CAM Run 3

Preciptator Readings

	Precipitator 7A					Precipitator 7B				
	TR-1A	TR-2A	TR-3A	TR4A	TR-5A	TR-1A	TR-2A	TR-3A	TR4A	TR-5A
Line Voltage	468	468	468	468	467	468	468	468	468	468
Primary Current	2.8	3.2	2.9	4.1	68.3	2.3	3.2	3.2	3.9	68.2
Total Power	1	1	1	1	24	1	1	0	1	24
Secondary kV	0.0	0.0	0.0	34.2	51.9	0.0	0.0	0.0	37.0	49.5
Secondary mA	3.1	4.9	3.1	19.8	399.6	4.1	4.7	5.0	19.8	399.7
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B	TR-1B	TR-2B	TR-3B	TR-4B	TR-5B
Line Voltage	468	468	467	467	466	467	467	467	467	466
Primary Current	3.1	3.1	0.2	4.0	67.9	0.0	2.5	0.2	4.1	67.8
Total Power	1	1	0	1	24	0	1	0	1	24
Secondary kV	0.0	0.0	0.0	36.0	52.4	0.0	0.0	0.0	38.3	50.9
Secondary mA	4.1	3.3	4.9	19.8	399.8	2.0	5.0	3.1	19.8	399.8
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0
	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C	TR-1C	TR-2C	TR-3C	TR-4C	TR-5C
Line Voltage	467	467	467	466	466	467	467	466	466	466
Primary Current	0.0	3.2	0.3	4.1	67.5	3.0	0.2	2.8	4.1	68.0
Total Power	0	1	0	1	24	1	0	1	1	23
Secondary kV	0.0	0.0	0.0	34.8	51.6	0.0	0.0	0.0	37.0	49.5
Secondary mA	1.7	4.7	3.4	19.9	399.8	5.0	4.7	3.3	19.9	399.2
Charge Ratio	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0	1 : 0
Sparks per Minute	0	0	0	0	0	0	0	0	0	0

From: McKinney, Jeff
Sent: Friday, June 18, 2004 4:02 PM
To: Dominey, John M.; Beaty, Kevin L.
Subject: June 17 LOI

CRIST PLANT LOI WORKSHEET

DATE = 6/17/2004

Unit 7 LOI's
Special testing

HOPPER	CRUCIBLE NUMBER	CRUCIBLE WEIGHT	CRUCIBLE AND SAMPLE WEIGHT	POST FURNACE WEIGHT	LOI
7A4-3	37	15.1349	16.3612	16.3008	4.93
7A4-3	81	15.033	16.2467	16.1925	4.47
7A4-4	5	15.486	16.5945	16.5404	4.88
7A4-4	18	14.3758	15.4263	15.3769	4.70
7B4-3	44	15.0928	15.9567	15.8855	8.24
7B4-3	13	14.744	15.844	15.755	8.09
7B4-4	70	14.9409	15.8236	15.7303	10.57
7B4-4	4	15.1493	16.159	16.0511	10.69

Beaty, Kevin L.

From: Cotsonis, Van L.
Sent: Thursday, June 17, 2004 4:57 PM
To: Dominey, John M.; Beaty, Kevin L.
Cc: O'Mary, Arthur L.
Subject: June 14 LOI

The middle hopper results are from a composite sample taken from all hoppers in the next row back from the front row. These hoppers lacked enough ash to make a sample from each hopper.

CRIST PLANT LOI WORKSHEET

DATE = 6/17/2004

Unit 7 LOI's
EPCT STEADY STATE

HOPPER	CRUCIBLE NUMBER	CRUCIBLE WEIGHT	CRUCIBLE AND SAMPLE WEIGHT	POST FURNACE WEIGHT	LOI
7A2 Front	64	14.8848	15.9287	15.9105	1.74
7A2 Front	70	14.9382	16.0115	16.0043	0.67
7A3Front	4	15.1481	16.1585	16.1440	1.44
7A3Front	5	15.9847	16.4994	16.4798	3.81
7A2 Middle	11	14.0598	15.0349	14.9596	7.72
7A2 Middle	18	14.3742	15.3983	15.3180	7.84
7A4 Middle	86	14.1688	15.1990	15.1641	3.39
7A4 Middle	7	14.2591	15.2592	15.2269	3.23
7B3 Front	41	15.4544	16.4777	16.4584	1.89
7B3 Front	57	15.2728	16.2311	16.2128	1.91
7B4 Front	44	15.0917	16.1369	16.1084	2.73
7B4 Front	81	15.0329	16.0810	16.0492	3.03
7B2 Middle	13	14.7432	15.7485	15.7090	3.93
7B2 Middle	37	15.1350	16.1224	16.0877	3.51

Beaty, Kevin L.

From: McKinney, Jeff
Sent: Friday, June 18, 2004 4:02 PM
To: Dominey, John M.; Beaty, Kevin L.
Subject: June 17 LOI

CRIST PLANT LOI WORKSHEET

DATE = 6/17/2004

Unit 7 LOI's
Special testing

HOPPER	CRUCIBLE NUMBER	CRUCIBLE WEIGHT	CRUCIBLE AND SAMPLE WEIGHT	POST FURNACE WEIGHT	LOI
7A4-3	37	15.1349	16.3612	16.3008	4.93
7A4-3	81	15.033	16.2467	16.1925	4.47
7A4-4	5	15.486	16.5945	16.5404	4.88
7A4-4	18	14.3758	15.4263	15.3769	4.70
7B4-3	44	15.0928	15.9567	15.8855	8.24
7B4-3	13	14.744	15.844	15.755	8.09
7B4-4	70	14.9409	15.8236	15.7303	10.57
7B4-4	4	15.1493	16.159	16.0511	10.69

Visible Emissions Observation Form

COMPLIANCE STATUS: YES | NO | N/A

Source/Process Information

FACILITY NAME: Gulf Power Company
SOURCE NAME: CRIST UNIT 7
PERMIT NO:
LOCATION/ADDRESS: Pensacola, Florida
CONTACT: John Dominey
PHONE NO: 850.429.2219
PROCESS/PRODUCTION RATE: COAL FIRED Electric Generator
CONTROL EQUIPMENT: Electrostatic Precipitator
OPERATING MODE: *
FUEL TYPE/RATE: BITUMINOUS
MATERIAL TYPE/RATE:
PERMITTED RATE: 500MW
DESCRIBE EMISSION POINT: Leftmost (Northmost) of two 450' Stacks
HEIGHT ABOVE GROUND LEVEL: ~450 FT
HEIGHT RELATIVE TO OBSERVER: ~400 FT

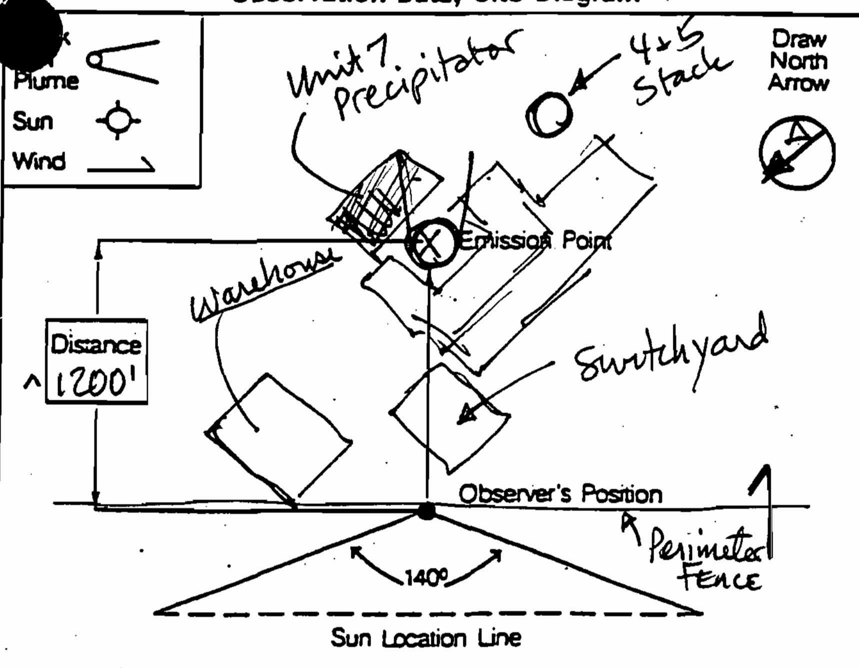
Emissions Description

DESCRIBE EMISSIONS: START Lo Grey intermittent puffs — END same
PLUME COLOR: Grey
PLUME TYPE: Lofting
WATER DROPLETS PRESENT? YES ☐ NO ☑
IF YES, IS PLUME: ATTACHED ☑ DETACHED ☐

Meteorological Information

BACKGROUND: START grey clouds END same
BACKGROUND COLOR: START grey END grey
SKY CONDITIONS/% CLOUD COVER: START Broken END Broken
AMBIENT TEMP: START 83°F END 84°F
WIND SPEED: START 1-3 END same
WIND DIRECTION: START W END W

Observation Data, Site Diagram



Opacity Readings

OBSERVATION DATE: 6/17/04
START TIME: 1358
STOP TIME: 1457

MIN \ SEC	0	15	30	45	MIN \ SEC	0	15	30	45
1	15	15	15	15	31	15	15	15	15
2	20	15	20	15	32	15	15	15	15
3	15	20	20	20	33	10	10	15	15
4	15	15	15	20	34	10	15	10	15
5	15	15	15	15	35	10	10	10	15
6	15	15	15	15	36	10	10	10	10
7	15	15	15	15	37	15	10	15	10
8	20	15	15	18	38	10	15	10	10
9	15	20	15	15	39	10	10	10	10
10	15	15	15	15	40	10	10	10	10
11	15	15	15	15	41	10	15	10	10
12	15	15	15	15	42	10	10	10	10
13	15	15	15	20	43	10	10	10	10
14	10	15	15	15	44	10	10	10	10
15	10	15	15	15	45	10	15	15	0
16	15	15	15	15	46	15	15	15	10
17	15	15	15	15	47	10	10	10	10
18	15	20	15	20	48	10	10	10	10
19	10	15	30	15	49	15	10	15	15
20	15	15	15	15	50	10	10	10	10
21	10	10	10	10	51	20	15	10	10
22	15	15	15	10	52	10	15	10	10
23	10	10	15	15	53	15	15	15	10
24	25	25	20	20	54	15	10	10	15
25	15	20	15	15	55	10	10	10	10
26	20	20	20	20	56	10	10	10	15
27	15	15	15	15	57	10	10	10	10
28	25	20	15	15	58	10	10	10	10
29	10	10	10	10	59	15	45	15	15
30	15	20	15	15	60	15	15	15	15

Compliance Information

RANGE OF OPACITY READINGS: MIN 10 MAX 45
AVERAGE OF HIGHEST 24 CONSECUTIVE READINGS: 17.1%
[redacted] TERM AVERAGE DATA: [redacted] PERIOD 6 min MINUTES ACTUAL AVERAGE 17.1%

Certification Data, Signatures

OBSERVERS NAME: John McPherson
OBSERVERS SIGNATURE: John McPherson DATE 6/17/04
ORGANIZATION: Gulf Power Company
CERTIFIED BY: ETA DATE 5/12/04
I HAVE RECEIVED A COPY OF THESE OBSERVATIONS. SIGNATURE DATE
APS NUMBER

COMMENTS:
* Precipitator was partially disabled for purposes of CAM Testing..
* Unit 6 was ~~on-line~~
* Background did not provide a good contrast!

General Test Laboratory
P.O. Box 2641
Birmingham, Alabama 35291
(205) 664 - 6081

CERTIFICATE OF ANALYSIS

TO: Plant Crist
Gulf Power Co.

Customer Account : CRI07SP
Sample Date : 17-Jun-04

Laboratory Account : CRI07SP
Received Date : 25-Jun-04

Description : Gulf Power Plant Crist Unit 7

CAM CONDITION 1 RUN 1

Laboratory ID Number : AI17554

Test Name	Reference	Result	Units
Dry Basis			
Ash, Dry	ASTM D 5142	4.28	% By Weight
Heat of Combustion, Dry	ASTM D 5865	13409	Btu/lb
Carbon, Dry Basis	ASTM D 5373	77.29	% By Weight
Hydrogen, Dry Basis	ASTM D 5373	4.95	% By Weight
Nitrogen, Dry Basis	ASTM D 5373	1.46	% By Weight
Oxygen, Dry Basis	ASTM D 3176	11.60	% By Weight
Carbon Fixed, Dry	ASTM D 3172	57.88	% By Weight
Volatiles, Dry Basis	ASTM D 5142	37.84	% By Weight
Sulfur, Dry Basis	ASTM D 4239	0.42	% By Weight
As Received			
Moisture, Total	ASTM D 2013	14.91	% By Weight
Ash, As Received	ASTM D 5142	3.64	% By Weight
Heat of Combustion, As Received	ASTM D 5865	11410	Btu/lb
Carbon, As Received	ASTM D 5373	65.77	% By Weight
Hydrogen, As Received	ASTM D 5373	4.21	% By Weight
Nitrogen, As Received	ASTM D 5373	1.24	% By Weight
Oxygen, As Received	ASTM D 3176	9.87	% By Weight
Carbon Fixed, As Received	ASTM D 3172	49.25	% By Weight
Volatiles, As Received	ASTM D 5142	32.20	% By Weight
Sulfur, As Received	ASTM D 4239	0.36	% By Weight
General			
Heat of Combustion, MAF	ASTM D 5865	14009	Btu/lb
Sulfur, lbs/mmBTU	ASTM D 3180	0.313	lbs/mmBTU

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments:

CC: Kevin Beaty
John Dominey
Randy Alexander

Quality Control ______________________ **Supervision**____________________________ Date : 7/2/2004

smk/coa

General Test Laboratory
P.O. Box 2641
Birmingham, Alabama 35291
(205) 664 - 6081

CERTIFICATE OF ANALYSIS

TO: Plant Crist
Gulf Power Co.

Customer Account : CRI07SP
Sample Date : 17-Jun-04

Laboratory Account : CRI07SP
Received Date : 25-Jun-04

Description : Gulf Power Plant Crist Unit 7

CAM CONDITION 1 RUN 2

Laboratory ID Number : AI17555

Test Name	Reference	Result	Units
Dry Basis			
Ash, Dry	ASTM D 5142	4.70	% By Weight
Heat of Combustion, Dry	ASTM D 5865	13349	Btu/lb
Carbon, Dry Basis	ASTM D 5373	76.98	% By Weight
Hydrogen, Dry Basis	ASTM D 5373	4.82	% By Weight
Nitrogen, Dry Basis	ASTM D 5373	1.52	% By Weight
Oxygen, Dry Basis	ASTM D 3176	11.41	% By Weight
Carbon Fixed, Dry	ASTM D 3172	57.42	% By Weight
Volatiles, Dry Basis	ASTM D 5142	37.88	% By Weight
Sulfur, Dry Basis	ASTM D 4239	0.57	% By Weight
As Received			
Moisture, Total	ASTM D 2013	13.54	% By Weight
Ash, As Received	ASTM D 5142	4.06	% By Weight
Heat of Combustion, As Received	ASTM D 5865	11542	Btu/lb
Carbon, As Received	ASTM D 5373	66.56	% By Weight
Hydrogen, As Received	ASTM D 5373	4.17	% By Weight
Nitrogen, As Received	ASTM D 5373	1.31	% By Weight
Oxygen, As Received	ASTM D 3176	9.87	% By Weight
Carbon Fixed, As Received	ASTM D 3172	49.65	% By Weight
Volatiles, As Received	ASTM D 5142	32.75	% By Weight
Sulfur, As Received	ASTM D 4239	0.49	% By Weight
General			
Heat of Combustion, MAF	ASTM D 5865	14007	Btu/lb
Sulfur, lbs/mmBTU	ASTM D 3180	0.427	lbs/mmBTU

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments:

CC: Kevin Beaty
John Dominey
Randy Alexander

Quality Control ______________________ **Supervision** ____________________________ Date : 7/2/2004

smk/coa

General Test Laboratory
P.O. Box 2641
Birmingham, Alabama 35291
(205) 664 - 6081

CERTIFICATE OF ANALYSIS

TO: Plant Crist
Gulf Power Co.

Customer Account : CRI07SP
Sample Date : 17-Jun-04
Laboratory Account : CRI07SP
Received Date : 25-Jun-04

Description : Gulf Power Plant Crist Unit 7

CAM CONDITION 1 RUN 3

Laboratory ID Number : AI17556

Test Name	Reference	Result	Units
Dry Basis			
Ash, Dry	ASTM D 5142	5.25	% By Weight
Heat of Combustion, Dry	ASTM D 5865	13258	Btu/lb
Carbon, Dry Basis	ASTM D 5373	76.74	% By Weight
Hydrogen, Dry Basis	ASTM D 5373	4.97	% By Weight
Nitrogen, Dry Basis	ASTM D 5373	1.53	% By Weight
Oxygen, Dry Basis	ASTM D 3176	10.92	% By Weight
Carbon Fixed, Dry	ASTM D 3172	56.80	% By Weight
Volatiles, Dry Basis	ASTM D 5142	37.95	% By Weight
Sulfur, Dry Basis	ASTM D 4239	0.59	% By Weight
As Received			
Moisture, Total	ASTM D 2013	12.12	% By Weight
Ash, As Received	ASTM D 5142	4.61	% By Weight
Heat of Combustion, As Received	ASTM D 5865	11651	Btu/lb
Carbon, As Received	ASTM D 5373	67.44	% By Weight
Hydrogen, As Received	ASTM D 5373	4.37	% By Weight
Nitrogen, As Received	ASTM D 5373	1.34	% By Weight
Oxygen, As Received	ASTM D 3176	9.60	% By Weight
Carbon Fixed, As Received	ASTM D 3172	49.92	% By Weight
Volatiles, As Received	ASTM D 5142	33.35	% By Weight
Sulfur, As Received	ASTM D 4239	0.52	% By Weight
General			
Heat of Combustion, MAF	ASTM D 5865	13993	Btu/lb
Sulfur, lbs/mmBTU	ASTM D 3180	0.445	lbs/mmBTU

This Certificate states the physical and/or chemical characteristics of the sample as submitted.

Comments:

CC: Kevin Beaty
John Dominey
Randy Alexander

Quality Control ______________________ **Supervision**____________________________ Date : 7/2/2004

smk/coa