

## **ATTACHMENT A**

Survey map of site



GRAPHIC SCALE

( IN FEET )  
1 inch = 40 ft.

EASEMENTS DESCRIBED IN

TAMPA ELECTRIC COMPANY  
PARCEL #252815000000033030  
O.R. 3191, PG. 2168  
(UNPLATTED LANDS)

AUBURNDALE MEMORIAL PARK  
PARCEL #252816000000011020  
P.B. 85, PGS. 41 & 42

SURVEYOR'S NOTES:

- 1) Underground improvements, if any, have not been located.
- 2) Bearings are based on the assumed bearing of N 89°41'16"W along the North right-of-way line of State Road S-655 (Recker Highway).
- 3) At the time of the field survey, there was no observable evidence of earth moving work, building construction or building additions within recent months; there also was no observable evidence of site use as a solid waste dump, sump or sanitary landfill.

TITLE COMMITMENT NOTES:

The easements and other title matters shown hereon were taken from Title Commitment File Number FA-C-394164-2, issued by First American Title Insurance Company, effective April 08, 2009 at 8:00 A.M., and was relied upon to be complete and correct. The following items refer to Schedule B-II of said commitment:

DATE ISSUED: MAY 12, 2009

9) SUBJECT TO Utility Easement recorded in Book 3359, Page 1784. (Shown)

10) SUBJECT TO the terms, provisions and conditions contained in that certain Ordinance No. 985, recorded in Book 4406, Page 1542. (Subject Parcel annexed into the City of Auburndale, Florida)

11) SUBJECT TO the terms, provisions and conditions contained in that certain Boundary Line Agreement dated 1988 between the County of San Diego and the City of Escondido.

13) SUBJECT TO Easement recorded in Book 5054, Page 1061. (Temporary workspaces shown)

14) SUBJECT TO Easement recorded in Book 5421, Page 1177. (Permanent non-exclusive easement)

This survey is made for the benefit of:  
 Calpine Construction Finance Company, LP, Wilmington Trust Company, as Collateral Trustee, Stewart Title Guaranty Company, First American Title Insurance Company, and their respective successors and assigns.  
 I, Ralph H. Whisler III, Professional Land Surveyor do hereby certify to the aforesaid parties, as of the date set forth above that I have made a careful survey of a tract of land described as follows:

This is to certify that this map or plat and the survey on which it is based were made in accordance with the "Minimum Standard Detail Requirements for ALTA/ACSM Land Title Surveys," jointly established and adopted by ALTA and NSPS in 2005, and includes Items 1, 2, 3, 4, 6, 7(c), 8, 9, 10, 11(b), 13, 14, 16, and 18 of Table A thereof. Pursuant to the Accuracy Standards as adopted by ALTA and NSPS and in effect on the date of this certification, undersigned further certifies that in my professional opinion, as a land surveyor registered in the State of Florida, the Relative Positional Accuracy of this survey does not exceed that which is specified therein.

The accompanying survey was made on the ground and correctly shows the location of all buildings, structures and other improvements situated on the above premises; there are no visible encroachments on the subject property or upon adjacent land abutting said property except as shown hereon and was made in accordance with laws and/or Minimum Standards of the State of Florida.

The property described hereon is the same as the property described in First American Title Insurance Company Commitment No. FA-C-394164-2 with an effective date of 04/08/2009 at 8:00AM, Issued May 12, 2009 and that all easements, covenants and restrictions referenced in said title commitment or apparent from a physical inspection of the site or otherwise known to me have been plotted hereon or otherwise noted as to their effect on the subject property.

Said described property is located within an area having a Zone Designation "X" by the Federal Emergency Management Agency (FEMA), on Flood Insurance Rate Map No.12105C0345 F, effective 12-2-2000, for Community No. 120261, in Polk County, State of Florida, which is the current Flood Insurance Rate Map for the community in which said premises is situated.

The Property has direct access to Derby Avenue (C.R.544-A & Recker Highway (S.R. S-655), a dedicated public street or highway.

The total number of striped parking spaces on the subject property is 20, including 2 designated handicap spaces.

Name: RALPH H. WHISLER III, P.L.S.  
 Address: 363 U.S. 27 SOUTH, SEBRING, FLORIDA 33870

Professional Land Surveyor License No.: L.B. #262

ZONING INFORMATION:

According to the City of Auburndale Official Zoning Map (dated March 17, 2009), the Subject Parcel is located in zone LI – Light Industrial. Per the City of Auburndale Land Development Regulations for Zone LI, Light Industrial:

5.6.14.7 - MINIMUM YARD REQUIREMENTS:  
Front - 25 feet  
Side - 15 feet (with provisions)  
Rear - 20 feet (with provisions)

5.6.14.8 - MAXIMUM LOT COVERAGE BY ALL BUILDINGS:  
As needed to meet other requirements therein

5.6.14.9 - MAXIMUM IMPERVIOUS SURFACE COVERAGE:  
70% for upland soils. All other soils shall remain unimproved.

5.6.14.10 - MAXIMUM HEIGHT OF STRUCTURES:  
Except as provided in Sec. 5.2.4, no portion shall exceed 150 feet.

5.6.14.11.1.2 - MINIMUM OFF-STREET PARKING REQUIREMENTS:  
Parking space shall be determined by the administrative official in an amount appropriate to the circumstances of the case, but in no case

shall off-street parking space required be less than one space for each employee on peak shifts.

DESCRIPTION:  
THE WEST 1/2 OF THE NORTHWEST 1/4 OF THE NORTHWEST 1/4 OF SECTION 15, TOWNSHIP 28 SOUTH, RANGE 25 EAST, POLK COUNTY, FLORIDA, LESS ROAD RIGHTS OF WAY.  
IS ONE IN THE SAME:

THE WEST 1/2 OF THE NORTHWEST 1/4 OF THE NORTHWEST 1/4 OF SECTION 15, TOWNSHIP 28 SOUTH, RANGE 25 EAST, POLK COUNTY, FLORIDA, LESS AND EXCEPT THAT CERTAIN PROPERTY CONVEYED BY QUIT CLAIM DEED RECORDED IN DEED BOOK 972, PAGE 357 AND LESS AND EXCEPT THAT CERTAIN PROPERTY CONVEYED BY QUIT CLAIM DEED RECORDED IN OFFICIAL RECORDS BOOK 666, PAGE 640, AND AS MODIFIED BY A BOUNDARY LINE AGREEMENT RECORDED OCTOBER 12, 2001 IN OFFICIAL RECORDS BOOK 4822, PAGE 1799, AND AS AMENDED BY THAT CERTAIN FIRST AMENDMENT TO BOUNDARY LINE AGREEMENT RECORDED IN OFFICIAL RECORDS BOOK 4837, PAGE 688, OF THE PUBLIC RECORDS OF POLK COUNTY, FLORIDA.

LEGEND.

[illegible]

engineers — architects — surveyors — scientists

**chastain  
skillman**  
incorporated

**3**

Sebring Survey Office:  
363 U.S. Highway 27 South, Sebring, Florida 33870 (863) 382-4160

Lakeland  
Sebring  
Tampa  
Orlando  
Atlanta

CALPINE CORPORATION  
OSPREY ENERGY CENTER  
ALTA/ACSM LAND TITLE SURVEY

|                         |
|-------------------------|
| <b>FIELD BOOK:</b>      |
| <b>FB S-132 - PG 33</b> |
| <b>SCALE:</b>           |
| <b>1"= 40'</b>          |
| <b>DATE OF SURVEY:</b>  |
| <b>05/04/2009</b>       |
| <b>DRAWING NO.</b>      |
| <b>ESS-7287.19A</b>     |



## **APPENDIX I**

### **PSD and Air Construction Permits**

STATE OF FLORIDA  
DEPARTMENT OF ENVIRONMENTAL PROTECTION  
**NOTICE OF PERMIT**

In the Matter of an  
Application for Permit by:

Robert K. Alff  
Senior Vice President, Calpine Eastern Corporation  
The Pilot House, 2<sup>nd</sup> Floor, Lewis Wharf  
Boston, MA 02110

DEP File No. PSD-FL-287  
Osprey Energy Center  
Polk County

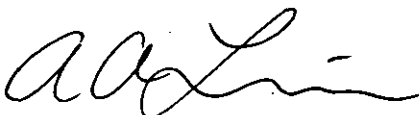
Enclosed is the Final Permit Number PSD-FL-287 This permit authorizes Calpine to construct a natural-gas fired combined cycle power plant known as Osprey Energy Center in Auburndale, Polk County. This permit is issued pursuant to Chapter 403, Florida Statutes and 40CFR52.21.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

In addition to the appeal process described above, federal appeals procedures concerning this PSD permit are outlined in 40CFR 124.19, which is attached. Any person who filed comments on the draft permit may petition the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments on the draft permit may petition for administrative review only to the extent of the changes from the draft to the final permit decision.

The petition must be filed with the Environmental Appeals Board within 30 days of issuance of this Notice. Petitions may be addressed to the Environmental Appeals Board, MC 1103B, U.S. Environmental Protection Agency, 401 M Street, Washington, D.C. 20460. Further details are available at [www.epa.gov/eab](http://www.epa.gov/eab).

Executed in Tallahassee, Florida.

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



## **FINAL DETERMINATION**

Calpine Construction & Finance Company, L.P.  
Osprey Energy Center Combined Cycle Plant  
DEP File No. PA 00-41, PSD-FL-287

The Department distributed a public notice package on May 10, 2000 to allow the applicant to construct the Osprey Energy Center combined cycle power plant in Auburndale, Polk County. The Public Notice of Intent to Issue was published in the Lakeland Ledger on April 12, 2001.

### **COMMENTS/CHANGES**

Comments were received from the EPA on June 21, 2000.

Comments on the draft permit were received from the applicant by letter dated September 5, 2000.

Comments were reviewed and incorporated into the Draft Conditions of Certification.

Pursuant to notice, the Division of Administrative Hearings, by its duly designated Administrative Law Judge, J. Lawrence Johnston, conducted a formal site certification hearing (Case No. 00-1288EPP) in this proceeding on April 17, 2001 in Auburndale, Florida. On May 23, 2001, it was recommended that the Siting Board grant full and final certification to Calpine, under Section 403, Part II, Florida Statutes, for the location, construction, and operation of Brandy Branch, representing a combined cycle unit, as described in the Draft Conditions of Certification and the evidence presented at the certification hearing.

On June 27, 2001 the Siting Board concurred with the Administrative Law Judge's recommendation and authorized issuance of related permits via its Final Order.

### **CONCLUSION**

The final action of the Department is to issue the permit consistent with changes described above.



### 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 mailed by U.S. Mail before the close of business on 7-5-01 to the person(s) listed:

Robert K. Alff, Senior VP, Calpine Eastern Corporation \*

Mr. Benjamin Borsch, Environmental Manager, Calpine \*

Mr. Kennard F. Kosky, P.E. Golder

Mr. David S. Dee, Landers & Parsons

Mr. Bill Thomas, SWD-DEP

Hamilton S. Oven, DEP-Siting

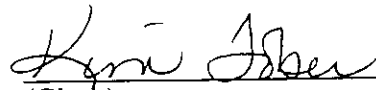
Mr. Gregg Worley, EPA

Mr. John Bunyak, NPS

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.

 7-5-01  
(Clerk) (Date)



Jeb Bush  
Governor

# Department of Environmental Protection

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

David B. Struhs  
Secretary

## PERMITTEE:

Calpine Construction Finance Company, LP (Calpine)  
The Pilot House, 2<sup>nd</sup> floor, Lewis Wharf  
Boston, MA 02110

|          |                      |
|----------|----------------------|
| File No. | PSD-FL-287 (PA00-41) |
| FID No.  | 1050334              |
| SIC No.  | 4911                 |
| Expires: | December 31, 2003    |

## Authorized Representative:

Mr. Robert K. Alff, Senior Vice President

## PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of a nominal 527 megawatt (MW) Combined Cycle plant consisting of: two nominal 170 MW gas-fired, stationary combustion turbine-electrical generators fired solely on natural gas; two supplementally-fired heat recovery steam generators (HRSGs); a nominal 200 MW steam electrical generator; two stacks; an emergency (gas-fired) generator; a diesel fire pump; two selective catalytic reduction units including ancillary equipment and ammonia storage. The combined cycle plant will achieve approximately 585 megawatts in combined cycle operation during extreme winter peaking conditions. The facility is designated as Osprey Energy Center and will be situated adjacent to the Auburndale Power Partners facility, which is located at 1501 Derby Avenue, Auburndale, Polk County. UTM coordinates are: Zone 17; 421.0 km E; 3103.2 km N.

## STATEMENT OF BASIS:

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR52.21. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

The attached Appendix is made a part of this permit:

Appendix GC

Construction Permit General Conditions

Howard L. Rhodes, Director  
Division of Air Resources  
Management

"More Protection, Less Process"



# PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-287

## SECTION I - FACILITY INFORMATION

### FACILITY DESCRIPTION

The proposed Osprey Energy center is a nominal 527 MW combined cycle plant. It will include: two nominal 170 MW gas-fired, stationary combustion turbine-electrical generators fired solely on natural gas; two supplementally-fired heat recovery steam generators (HRSGs); a nominal 200 MW steam electrical generator; two stacks; an emergency (gas-fired) generator; a diesel fire pump; two selective catalytic reduction units including ancillary equipment and ammonia storage. New major support facilities include a cooling tower, water and wastewater facilities and a transmission line.

Emissions from Osprey Energy Center will be controlled by Dry Low NO<sub>x</sub> (DLN) combustors and selective catalytic reduction (SCR). Pipeline quality natural gas and good combustion practices will be employed to control all pollutants.

### EMISSIONS UNITS

This permit addresses the following emissions units:

| EMISSIONS UNIT | SYSTEM           | Emission Unit Description                                                                       |
|----------------|------------------|-------------------------------------------------------------------------------------------------|
| 001            | Power Generation | One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator                            |
| 002            | Power Generation | One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator                            |
| 003            | Steam Generation | One 250 MMBtu/hr Duct Burner configured as a Supplementally Fired Heat Recovery Steam Generator |
| 004            | Steam Generation | One 250 MMBtu/hr Duct Burner configured as a Supplementally Fired Heat Recovery Steam Generator |
| 005            | Water Cooling    | Cooling Tower                                                                                   |
| xxx            | Miscellaneous    | Emergency Generator and Diesel Fire Pump                                                        |

### REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM<sub>10</sub>), sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

# **PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-287**

## **SECTION I - FACILITY INFORMATION**

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This facility is within an industry (fossil fuel-fired steam electric plant) included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of SO<sub>2</sub> and NO<sub>x</sub>, 25/15 TPY of PM/PM<sub>10</sub>, 100 TPY of CO and 40 TPY of VOC's. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This project is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is greater than 75 MW. [Chapter 403.503 (12), F.S., Definitions]

This facility is also subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

### **PERMIT SCHEDULE**

- 06/29/01 PSD Permit Issued
- 06/27/01 Site Certification Issued
- 04/12/01 Notice of Intent to Issue PSD Permit published in The Lakeland Ledger
- 05/10/00 Distributed Intent to Issue Permit
- 03/30/00 Received PSD Application

### **RELEVANT DOCUMENTS:**

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but are not incorporated into this permit. These documents are on file with the Department.

- Application received on March 30, 2000.
- Letter from Fish & Wildlife Service dated April 17, 2000.
- Department's Intent to Issue and Public Notice Package dated May 10, 2000.
- Department's Draft Permit and Draft BACT determination dated May 10, 2000.
- Letter from EPA Region IV dated June 21, 2000.
- Recommended Order of Judge J. Lawrence Johnston dated May 23, 2001.
- Site Certification for the Osprey Energy Center dated June 27, 2001.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.



# PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-287

## SECTION II - ADMINISTRATIVE REQUIREMENTS

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### GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District Office, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 and phone number 813/744-6100.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21 (j) and 40 CFR 51.166(j), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 52.21(j), 40 CFR 51.166(j) and Rule 62-4.070 F.A.C.]
8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit. In conjunction with extension of the 18-month periods to commence or continue construction, or extension of the December 31, 2003 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.080, F.A.C.]

## PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-287

### SECTION II - ADMINISTRATIVE REQUIREMENTS

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9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]
10. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Southwest District Office. [Chapter 62-213, F.A.C.]
11. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
12. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southwest District Office by March 1st of each year.
13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Southwest District Office.

## PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-287

### SECTION III - EMISSIONS UNIT(S) SPECIFIC CONDITIONS

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#### APPLICABLE STANDARDS AND REGULATIONS

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.
2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
  - 40CFR60.7, Notification and Recordkeeping
  - 40CFR60.8, Performance Tests
  - 40CFR60.11, Compliance with Standards and Maintenance Requirements
  - 40CFR60.12, Circumvention
  - 40CFR60.13, Monitoring Requirements
  - 40CFR60.19, General Notification and Reporting requirements
4. ARMS Emissions Units 001 and 002. Direct Power Generation, each consisting of a nominal 170 megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).
5. ARMS Emissions Units 003 and 004. Steam Power Generation, each consisting of a supplementally-fired heat recovery steam generator equipped with a natural gas fired 250 MMBTU/hr duct burner (HHV) and combined with a 200 MW steam electrical generator shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.
6. ARMS Emission Unit 005. Cooling Tower, is an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because chromium-based chemical treatment is not used.
7. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District Office.

#### GENERAL OPERATION REQUIREMENTS

8. Fuels: Only pipeline natural gas shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
9. Combustion Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of the fuel to this Unit at ISO conditions shall not exceed 1,669 million Btu per hour (mmBtu/hr) when firing natural gas without power augmentation. This maximum heat input rate will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be



## PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-287

### SECTION III - EMISSIONS UNIT(S) SPECIFIC CONDITIONS

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provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 250 MMBtu/hour (LHV). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
11. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.
12. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Southwest District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]
13. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]
14. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]
15. Maximum allowable hours of operation for the 527 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. Fuel oil firing of the combustion turbine is not permitted. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
16. Simple Cycle Operation: The plant may not be operated without the use of the SCR system except during periods of startup and shutdown.

#### CONTROL TECHNOLOGY

17. Dry Low NO<sub>x</sub> (DLN) combustors shall be installed on each stationary combustion turbine and the permittee shall install a selective catalytic reduction system to comply with the NO<sub>x</sub> and ammonia limits listed in Specific Condition 20. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]
18. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 20 through 24. [Rule 62-4.070, Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]
19. Drift eliminators shall be installed on the cooling tower to reduce PM/PM<sub>10</sub> emissions. A certification following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002 gallons/100 gallons recirculation water flowrate.

## PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-287

### SECTION III - EMISSIONS UNIT(S) SPECIFIC CONDITIONS

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#### EMISSION LIMITS AND STANDARDS

20. Nitrogen Oxides (NO<sub>x</sub>) Emissions:

- The concentration of NO<sub>x</sub> in the stack exhaust gas, with the combustion turbine operating, the duct burner on or off, shall not exceed 3.5 ppmvd @15% O<sub>2</sub> on a 24-hr block average. This limit shall apply whether or not the unit is operating with duct burner on and/or in power augmentation mode. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- The emissions of NO<sub>x</sub> shall not exceed 27.5 lb/hr (at 95°F ambient temperature) while operating in the power augmentation mode with the duct burner on, to be demonstrated by annual stack test. [BACT Determination]
- Emissions of NO<sub>x</sub> from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition 29). [Applicant Request, Rule 62-4.070 and 62-204.800(7), F.A.C.]
- The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 9.0 ppmvd @15% O<sub>2</sub>. The compliance procedures are described in Specific Conditions 29 and 46. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO<sub>x</sub> monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

21. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas shall exceed neither 10 ppmvd @15% O<sub>2</sub> on a 24-hr block average to be demonstrated by CEMS for those days when no valid hour includes the use of duct burner firing, power augmentation or 60-70% operation (otherwise, the limit is 17 ppmvd @15% O<sub>2</sub> on a 24-hr block average to be demonstrated by CEMS); and neither 10 ppmvd @15% O<sub>2</sub> nor 45 lb/hr per unit at 100% output with the duct burner off and no power augmentation to be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing. [BACT, Rule 62-212.400, F.A.C.]

22. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall exceed neither 2.3 ppmvd @15% O<sub>2</sub> nor 5.8 lb/hr per unit with the duct burner off and neither 4.6 ppmvd @15% O<sub>2</sub> nor 12.4 lb/hr per unit with the duct burner on and operating in the power augmentation mode to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [BACT, Rule 62-212.400, F.A.C.]

23. Sulfur Dioxide (SO<sub>2</sub>) emissions: SO<sub>2</sub> emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 2 grains per 100 standard cubic foot). Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Condition 43 will demonstrate compliance with the applicable NSPS SO<sub>2</sub> emissions limitations from the duct burner or the combustion turbine. Note: This will effectively limit the combined SO<sub>2</sub> emissions for EU-001 and EU-002 at 95.4 tons per year. [BACT, 40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

24. PM/PM<sub>10</sub> and Visible emissions (VE): VE emissions shall not exceed 10 percent opacity from the stack in use. PM/PM<sub>10</sub> emissions from each combustion turbine and HRSG train shall not exceed 24.1

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### SECTION III - EMISSIONS UNIT(S) SPECIFIC CONDITIONS

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lb/hr at 100% output with the duct burner on and operating in the power augmentation mode to be demonstrated by initial stack test using EPA Method 5. [BACT, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

#### EXCESS EMISSIONS

25. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to and shutdowns from combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. Operation below 60% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [Rule 62-210.700, F.A.C.].
26. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO<sub>x</sub> and the 24-hr average for CO.
27. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Southwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions 40 through 46, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 20 through 24. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

#### COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.
29. Initial (I) performance tests shall be performed by the deadlines in Specific Condition 28. Initial tests shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or change of combustors, if specifically requested by the DEP on a case-by-case basis. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.

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- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA reference Method 5, "Determination of Particulate Emissions from Stationary Sources." Initial test only.
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement); Initial test for compliance with 40CFR60 Subpart GG; Initial (only) NO<sub>x</sub> compliance test for the duct burners (Subpart Da) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
- EPA Method 26A (modified) for ammonia sample collection (I, A).
- EPA Draft Method 206 for ion chromatographic analysis for ammonia (I,A).

The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O<sub>2</sub>) at the measured lb/hr NO<sub>x</sub> emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition 46.

30. Continuous compliance with the CO and NO<sub>x</sub> emission limits: Continuous compliance with the CO and NO<sub>x</sub> emission limits shall be demonstrated by the CEM system on the specified hour average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Valid hourly emission rates shall not include periods of start up or shutdown unless prohibited by 62-210.700 F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two measurements are obtained at least 15 minutes apart. Excess emissions periods shall be reported as required in Condition 27. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]
31. Compliance with the SO<sub>2</sub> and PM/PM<sub>10</sub> emission limits: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO<sub>2</sub> standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).
32. Compliance with CO emission limit: An initial and annual test for CO shall be conducted at 100% capacity with the duct burners off. The NO<sub>x</sub> and CO test results shall be the average of three valid



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one-hour runs. Annual RATA testing for the CO and NO<sub>x</sub> CEMS shall be required pursuant to 40 CFR 75.

33. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit will be employed as a surrogate and no annual testing is required.
34. Testing procedures: Unless otherwise specified, testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.
35. Test Notification: The DEP's Southwest District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance tests.
36. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.
37. Test Results: Compliance test results shall be submitted to the DEP's Southwest District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

#### NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by Calpine shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.
39. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

#### MONITORING REQUIREMENTS

40. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides and carbon monoxide from these units. Periods when emissions (ppmvd @ 15% oxygen) are above the permitted limits, listed in Specific Conditions No. 20 and 21 shall be reported to the DEP Southwest District Office in accordance with the requirements of Specific Condition 27. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].
41. CEMS for reporting excess emissions: The CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Upon request from DEP, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards listed within this permit and established in 40 CFR 60.332.

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42. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Bureau of Ambient Monitoring & Mobile Sources (BAMMS) as well as the EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.
43. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:
- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
  - The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to the sole use of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)) for the CT's.
  - Each unit shall be monitored for SO<sub>2</sub> emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
44. Determination of Process Variables:
- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. No later than 90 days prior to operation, the permittee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition.
  - Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh 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]
45. Subpart Da Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Da].
46. Selective Catalytic Reduction System (SCR) Compliance Procedures:
- An annual stack emission test for nitrogen oxides and ammonia from the CT/HRSG pair shall be simultaneously conducted while operating in the power augmentation mode with the duct burner on as defined in Specific Condition 20. The ammonia injection rate necessary to comply with the NO<sub>x</sub> standard shall be established and reported during the each performance test.
  - The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by manufacturer's guidelines and in accordance with this permit.

## PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-287

### SECTION III - EMISSIONS UNIT(S) SPECIFIC CONDITIONS

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- The permittee shall install and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of the CT/HRSG set. It shall be maintained and calibrated according to the manufacturer's specifications.
- During the stack test, the permittee (at each tested load condition) shall determine and report the ammonia flow rate required to meet the emissions limitations. During NO<sub>x</sub> CEM downtimes or malfunctions, the permittee shall operate at the ammonia flow rate, which was established during the last stack test.
- Ammonia emissions shall be calculated continuously using inlet and outlet NO<sub>x</sub> concentrations from the SCR system and ammonia flow supplied to the SCR system. The calculation procedure shall be provided with the CEM monitoring plan required by 40CFR Part 75. The following calculation represents one means by which the permittee may demonstrate compliance with this condition:

Ammonia slip @ 15%O<sub>2</sub> = (A-(BxC/1,000,000)) x (1,000,000/B) x D, where:

A = ammonia injection rate (lb/hr) / 17 (lb/lb.mol)

B = dry gas exhaust flow rate (lb/hr) / 29 (lb/lb.mol)

C = change in measured NO<sub>x</sub> (ppmv@15%O<sub>2</sub>) across catalyst

D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device utilized to make the ammonia emission measurement and submitted with each annual compliance test.

- The permittee shall notify the Department within 2 business days if the calculated ammonia emissions exceed 9.0 ppmvd corrected to 15% O<sub>2</sub> over a 3-hour block average. The notification shall include a corrective action plan to reduce ammonia emissions below 9 ppmvd corrected to 15% O<sub>2</sub> over a 3-hour block average.
- Upon specific request by the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements, in order to demonstrate that all NO<sub>x</sub> and ammonia slip related permit limits can be complied with.

**APPENDIX GC**  
**GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]**

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- G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
- G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
- G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
- G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
- G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
- G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
- G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
- a) Have access to and copy and records that must be kept under the conditions of the permit;
  - b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
  - c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.
- Reasonable time may depend on the nature of the concern being investigated.
- G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
- a) A description of and cause of non-compliance; and
  - b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

**APPENDIX GC**  
**GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]**

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The permittee shall be responsible for any and all damages, which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

- G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
- G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
- G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
- G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.
- G.13 This permit also constitutes:
- a) Determination of Best Available Control Technology (X)
  - b) Determination of Prevention of Significant Deterioration (X); and
  - c) Compliance with New Source Performance Standards (X).
- G.14 The permittee shall comply with the following:
- a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
  - b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
  - c) Records of monitoring information shall include:
    - 1. The date, exact place, and time of sampling or measurements;
    - 2. The person responsible for performing the sampling or measurements;
    - 3. The dates analyses were performed;
    - 4. The person responsible for performing the analyses;
    - 5. The analytical techniques or methods used; and
    - 6. The results of such analyses.
- G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law, which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.



**APPENDIX BD**  
**BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)**

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**Osprey Energy Center**  
**Calpine Construction Finance Company, L.P.**  
**PSD-FL-287 and PA00-41**  
**Auburndale, Polk County, Florida**

**BACKGROUND**

The applicant, Calpine Construction Finance Company, L.P. (Calpine), proposes to build a 527 MW (average ambient net megawatts) combined cycle power plant as a new facility. The location of the proposed plant is adjacent to the existing Auburndale Power Partners facility, in Auburndale, Polk County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM<sub>10</sub>), sulfur dioxide (SO<sub>2</sub>), sulfuric acid mist (SAM), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO<sub>x</sub>). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary units to be installed are two nominal 170 MW, Siemens Westinghouse "F" Class (501FD) combustion turbine-electrical generators, fired solely with pipeline natural gas and equipped with evaporative coolers on the inlet air system. The project includes two heat recovery steam generators (HRSGs), each with a 135 ft. stack and one steam turbine-electrical generator rated at approximately 200 MW. Duct burners will be installed in the HRSGs for supplemental firing and to achieve peak output. The project also includes a mechanical draft cooling tower, an emergency (gas-fired) generator and a diesel fire pump. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated May 10, 2000, accompanying the Department's Intent to Issue.

**BACT APPLICATION:**

The application was received on March 30, 2000 and included a proposed BACT proposal prepared by the applicant's consultant, Golder Associates. The proposal is summarized in the table below (MW loads are assumed to be at 70% or higher).

| POLLUTANT                | CONTROL TECHNOLOGY                      | BACT PROPOSAL                                                                                                           |
|--------------------------|-----------------------------------------|-------------------------------------------------------------------------------------------------------------------------|
| PM/PM <sub>10</sub> , VE | Pipeline Natural Gas<br>Good Combustion | 10 Percent Opacity<br>9 ppmvd Ammonia Slip                                                                              |
| SO <sub>2</sub> / SAM    | Pipeline Natural Gas                    | 2 grains S / 100 scf                                                                                                    |
| CO                       | Pipeline Natural Gas<br>Good Combustion | 10 ppmvd<br>16 ppmvd with Duct Burners on (DB)<br>25 ppmvd during power augmentation (PA)<br>30 ppmvd during DB plus PA |
| VOC                      | Pipeline Natural Gas<br>Good Combustion | 2.3 ppmvd<br>4.6 ppmvd during DB plus PA                                                                                |
| NO <sub>x</sub>          | DLN & SCR                               | 4.0 ppmvd                                                                                                               |
| PM (cooling tower)       | High efficiency drift eliminators       | 0.002% drift loss                                                                                                       |

Based upon the applicant's submittal, the maximum annual emissions that the facility has the potential to emit (PTE) are as follows: 95 TPY SO<sub>2</sub>, 15 TPY SAM, 199 TPY PM/PM<sub>10</sub>, 258 TPY NO<sub>x</sub>, 797 TPY CO and 70 TPY of VOC.

## **APPENDIX BD**

### **BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)**

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#### **BACT DETERMINATION PROCEDURE:**

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

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

#### **STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:**

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO<sub>x</sub> @ 15% O<sub>2</sub> (assuming 25 percent efficiency) and 150 ppmvd SO<sub>2</sub> @ 15% O<sub>2</sub> (or <0.8% sulfur in fuel). The BACT proposed by Calpine is consistent with the NSPS, which allows NO<sub>x</sub> emissions in the range of 110 ppmvd for the high efficiency units to be purchased. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

The duct burners required for supplementary gas-firing of the HRSGs are subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The 0.1 lb/MW-hr NO<sub>x</sub> emission rate proposed by Calpine is well below the revised Subpart Da output-based limit of 1.6 lb/MW-hr promulgated on September 3, 1998. No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines or gas-fired duct burners.

The gas-fired emergency generator and diesel fire pump will only be operated a few hours per month (so as to ensure their reliability for emergency use) and are considered insignificant for this analysis.

#### **DETERMINATIONS BY EPA AND STATES:**

The following table is a sample of information on some recent BACT determinations by states for combined cycle stationary gas turbine projects. These are projects incorporating large prime movers capable of producing more than 150 MW excluding the steam cycle. Such units are typically categorized as F or G Class Frame units. The applicant's proposed BACT is included for reference.

**APPENDIX BD**  
**BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)**

**TABLE 1**  
**RECENT BACT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS**  
**TURBINE COMBINED CYCLE PROJECTS**

| Project Location             | Power Output<br>Megawatts | NO <sub>x</sub> Limit<br>ppmvd @ 15% O <sub>2</sub><br>and Fuel | Technology               | Comments                                                                         |
|------------------------------|---------------------------|-----------------------------------------------------------------|--------------------------|----------------------------------------------------------------------------------|
| Mobile Energy, AL            | ~250                      | ~3.5 - NG (CT&DB)<br>~11 - FO (CT&DB)                           | DLN & SCR                | 178 MW GE 7FA CT 1/99<br>585 mmBtu Duct Burner                                   |
| KUA Cane Island 3            | 250                       | 3.5 - (CT&DB)                                                   | DLN/SCR                  | 170 MW GE 7FA. 11/99<br>Ammonia slip = 5 ppmvd                                   |
| Lake Worth LLC, FL           | 250                       | 9/3.5 - NG (CT)<br>9.4/3.5 - (CT&DB)<br>42 - FO                 | DLN/SCR<br>DLN/SCR<br>WI | 170 MW GE 7FA. 11/99<br>Increase allowed for DB.<br>Project repowers one + units |
| Calpine Sutter               | 545                       | 2.5 - (CT)<br>1 hour average (LAER)                             | DLN/SCR                  | Nearly identical to Osprey.                                                      |
| Calpine Delta                | 880                       | 2.5 - (CT & DB)<br>1 hour average (LAER)                        | DLN/CSR                  | 3 GE 7FA's or 3 WH 501FD's;<br>10 ppm max ammonia slip                           |
| Calpine Bullhead City        | 545                       | 3.0 - (CT&DB)                                                   | DLN/SCR                  | Nearly identical to Osprey;<br>Replace SCR catalyst after 36 mo.                 |
| Calpine Osprey<br>(proposed) | 545                       | 4.0 - (CT& DB)                                                  | DLN/SCR                  | Ammonia slip design = 9 ppm                                                      |

DB = Duct Burner  
NG = Natural Gas  
FO = Fuel Oil

DLN = Dry Low NO<sub>x</sub> Combustion  
SCR = Selective Catalytic Reduction  
WI = Water or Steam Injection

PA = Power Augmentation  
WH = Westinghouse  
GE = General Electric

**TABLE 2**  
**RECENT BACT LIMITS FOR CARBON MONOXIDE, VOLATILE ORGANIC**  
**COMPOUNDS, PARTICULATE MATTER, AND VISIBILITY FOR LARGE STATIONARY**  
**GAS TURBINE COMBINED CYCLE PROJECTS**

| Project Location             | CO - ppmvd<br>(or lb/mmBtu)                                        | VOC - ppm<br>(or lb/mmBtu)                        | PM - lb/mmBtu<br>(or gr/dscf or lb/hr)  | Technology and<br>Comments     |
|------------------------------|--------------------------------------------------------------------|---------------------------------------------------|-----------------------------------------|--------------------------------|
| Mobile Energy, AL            | ~18 - NG (CT&DB)<br>~26 - FO (CT&DB)                               | ~5 - NG<br>~6 - FO                                | 10% Opacity                             | Clean Fuels<br>Good Combustion |
| KUA Cane Island              | 10 - NG (CT)<br>20 - NG (CT&DB)<br>30 - FO                         | 1.4 - NG (CT)<br>4 - NG (CT&DB)<br>10 - FO        | 10% Opacity                             | Clean Fuels<br>Good Combustion |
| Lake Worth LLC, FL           | 9 - NG (CT)<br>15 - NG (CT & DB)<br>20 - F.O. (3-hr)               | 1.4 - NG (CT)<br>1.8 - NG (CT & DB)<br>3.5 - F.O. | 10% Opacity                             | Clean Fuels<br>Good Combustion |
| Calpine Sutter               | 4 - NG<br>Oxidation Catalyst                                       |                                                   | 11.5 lb/hr                              | Clean Fuels<br>Good Combustion |
| Calpine Delta                | 10 - NG (CT & DB)<br>10 - NG (DB & PA)<br>3 hr avg. - No Ox. Cat.  | 2 - NG                                            | 0.25 gr.S/100 scf Nat. Gas              | Clean Fuels<br>Good Combustion |
| Calpine Bullhead City        | 10 - NG (CT & DB)<br>33.9 - NG (DB & PA)<br>3 hour rolling average | 1.5 - NG                                          | 18.3 lb/hr (CT)<br>22.8 lb/hr (DB & PA) | Clean Fuels<br>Good Combustion |
| Calpine Osprey<br>(proposed) | 10 - NG (CT only)<br>16 - NG (CT & DB)<br>30 - NG (DB & PA)        | 2.3 - NG (CT)<br>4.6 - NG (DB & PA)               | 10% Opacity<br>24.1 lb/hr (CT & DB)     | Clean Fuels<br>Good Combustion |

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**OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:**

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, key information reviewed by the Department includes:

- Master Overview for Alabama Power Plant Barry Project received in 1998
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island 3
- Letter from Air Quality Branch, Fish & Wildlife Service dated April 17, 2000
- Presentations by Black & Veatch and General Electric at EPA Region IV on March 4, 1999
- Letter from Black & Veatch to EPA Region IV dated March 10, 1999
- Letter from Black & Veatch to the Department and EPA Region IV dated March 24, 1999
- Texas Natural Resource Conservation Commission Draft Tier I BACT for August, 1999
- Texas Natural Resource Conservation Commission Website – [www.tnrcc.state.tx.us](http://www.tnrcc.state.tx.us)
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO<sub>x</sub> Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

**REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:**

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO<sub>x</sub> Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

**Nitrogen Oxides Formation**

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO<sub>x</sub> forms in the high temperature area of the gas turbine combustor. Thermal NO<sub>x</sub> increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO<sub>x</sub> formation. Prompt NO<sub>x</sub> is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO<sub>x</sub> is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO<sub>x</sub> control by lean combustion.

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Fuel NO<sub>x</sub> is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas, its use is not planned for this project.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O<sub>2</sub>). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O<sub>2</sub> for the proposed Calpine turbine. The proposed NO<sub>x</sub> controls will reduce these emissions significantly.

#### **NO<sub>x</sub> Control Techniques**

##### Wet Injection

Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NO<sub>x</sub> emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NO<sub>x</sub> control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NO<sub>x</sub> emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NO<sub>x</sub> emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NO<sub>x</sub> emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

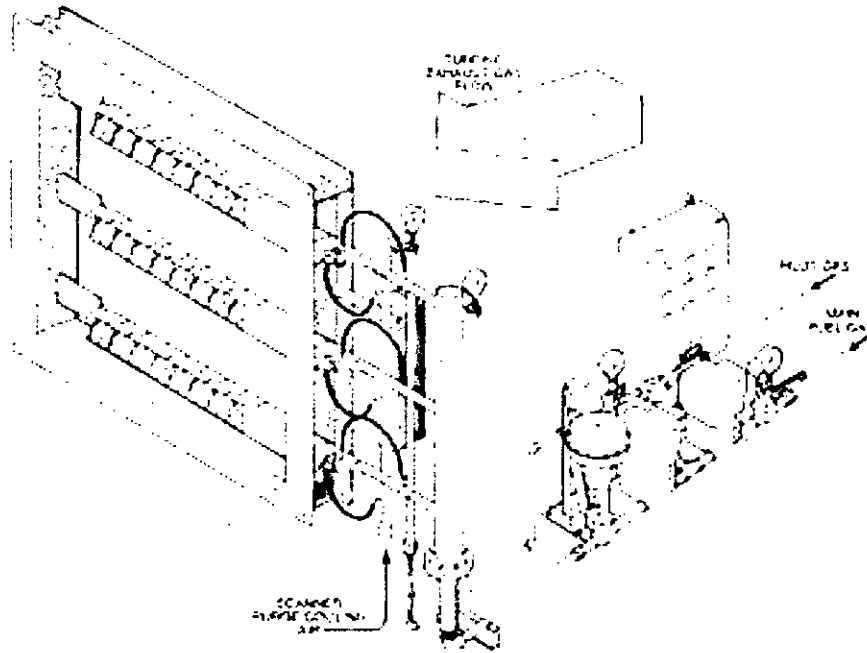
##### Combustion Controls

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% to 100% of base load and provides the lowest NO<sub>x</sub> emissions. Due to the intricate air and fuel staging necessary for dry low-NO<sub>x</sub> combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%.

Figure A (below) is an example of an in-line duct burner arrangement. Since duct burners operate at lower temperature and pressure than the combustion turbine, the potential for emissions is generally lower. Furthermore the duct burner size is only 250 MMBtu/hr compared with the turbine that can accommodate a heat input greater than 1600 MMBtu/hr (LHV). The duct burner will be of a Low NO<sub>x</sub> design and will be used to compensate for loss of capacity at high ambient temperatures.

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**FIGURE A**

**Selective Catalytic Combustion**

Selective catalytic reduction (SCR) is an add-on NO<sub>x</sub> control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO<sub>x</sub> emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO<sub>x</sub> in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3.

Figure B is a photograph of FPC Hines Energy Complex. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. Figure C below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met.

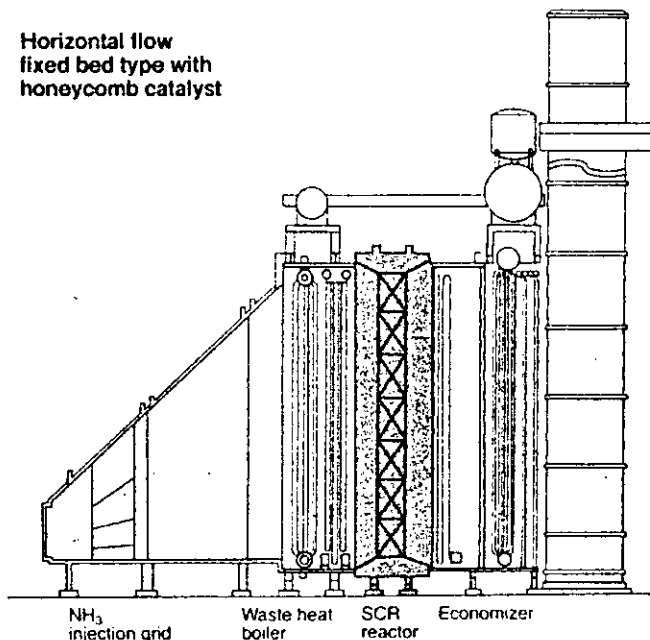


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**Figure B**



**Figure C**

Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur-bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO<sub>x</sub> have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits as low as 3.5 ppmvd NO<sub>x</sub> have been specified using SCR for at least one F Class project (with large in-line duct burners) in the Southeast and lower in the southwest.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market an SCNR for NO<sub>x</sub> control within the temperature ranges for which this project will operate (700 – 1400°F). However, the process also requires a low oxygen content in the exhaust stream in order to be effective. The oxygen levels greater than 12%, which are expected in this application, cause SNCR to not be technically feasible for the Calpine Osprey project.

Emerging Technologies: SCONOx<sup>TM</sup> and XONON<sup>TM</sup>

SCONOx<sup>TM</sup> is a catalytic technology that achieves NO<sub>x</sub> control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.<sup>1</sup> California regulators and industry sources have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx<sup>TM</sup>.<sup>2</sup> The overall project includes several more 250 MW blocks with SCR for control.<sup>3</sup> According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E has applied for the installation of SCONOx<sup>TM</sup> on an F frame unit at Otay Mesa in Southern California. Additionally, USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based

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upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOX<sup>TM</sup> system.

SCONOX<sup>TM</sup> technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO<sub>x</sub> reduction. Advantages of the SCONOX<sup>TM</sup> process include (in addition to the reduction of NO<sub>x</sub>) the elimination of ammonia and the control of VOC and CO emissions. SCONOX<sup>TM</sup> has not been applied on any major sources in ozone attainment areas, apparently only due to cost considerations. The Department is interested in seeing this technology implemented in Florida and intends to continue to work with applicants seeking an opportunity to demonstrate ammonia-free emissions on a large unit.

XONON<sup>TM</sup>, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO<sub>x</sub> combustion) followed by flameless catalytic combustion to further attenuate NO<sub>x</sub> formation. The technology has been demonstrated on combustors on the same order of size as SCONOX<sup>TM</sup> has. XONON<sup>TM</sup> avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON<sup>TM</sup> Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON<sup>TM</sup> Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON<sup>TM</sup> Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON<sup>TM</sup> system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON<sup>TM</sup> systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications.

**REVIEW OF PARTICULATE MATTER (PM/PM<sub>10</sub>) AND SO<sub>2</sub> CONTROL TECHNOLOGIES:**

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO<sub>x</sub> controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM<sub>10</sub>).

Natural gas is an inherently clean fuel and contains no ash. Natural gas will be the only fuel fired at the Osprey Energy Center and is efficiently combusted in gas turbines making any conceivable add-on control technique for PM/PM<sub>10</sub> or SO<sub>2</sub> either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM<sub>10</sub> as well as SO<sub>2</sub> is a combination of good combustion practices, fuel quality, and filtration of inlet air.

The applicant has identified PM emissions from the fresh-water cooling tower, due to an approximate 1400-ppm of suspended solids resulting from the use of reclaim water. Accordingly, drift eliminators shall be installed on the fresh-water cooling tower to reduce PM/PM<sub>10</sub>. The drift eliminators shall be designed

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and maintained to reduce drift to 0.002 percent of the circulating water flow rate. No PM testing is required because the Department's Emission Monitoring Section has determined that there is no appropriate PM test method for this type of cooling tower.

**REVIEW OF CARBON MONOXIDE(CO) CONTROL TECHNOLOGIES**

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Calpine Sutter in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.<sup>4</sup>

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO<sub>x</sub> emissions by SCR or dry low NO<sub>x</sub> means. Calpine proposes to meet a limit of 10 ppmvd while firing natural gas above 70% output with the duct burner off. However, the applicant proposes higher values of 16, 25 and 30 for the operating modes of duct burner firing, power augmentation and their combination, respectively. The combined operating modes have been requested for 2880 hours per year. The applicant additionally notes that CO emissions approach 50 ppmvd at loads between 60% and 70% and requests the ability to operate up to 1500 hours per year in this reduced output range.

The Department has not reviewed an extensive body of actual data, but has reasonable assurance that the WH 501FD unit selected by Calpine will achieve values below those proposed, without requiring installation of an oxidation catalyst. However, the authorized hours of off-normal operation will be decreased from the applicant's request to 2 hours per day at 60% - 70% output as well as 2 hours per day for each of the above operating modes (on an equivalent basis). The remaining 16 equivalent hours per day will be allotted for routine (10 ppmvd CO emission rate) operation. The Department will require the use of a CEMS for compliance on a 24-hour block average, with two limits depending upon actual operation. The limits will be:

- a) 10 ppmvd based upon a 24-hour block average for those days when no valid hour includes the use of duct burner firing, power augmentation or 60-70% operation; otherwise, the limit is
- b) 17 ppmvd based upon a 24-hour block average {rationale: 10 ppmvd x 16/24 hours plus 16 ppmvd x 2/24 hours plus 25 ppmvd x 2/24 hours plus 30 ppmvd x 2/24 hours plus 50 ppmvd x 2/24 hours}

**REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES**

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by Calpine for this project are 4.2 ppm with the duct burner off (between 60% and 70% output) and 4.6 ppm with the duct burner on during power augmentation. According to the applicant's submittals, VOC emissions less than 3 ppm will be achieved at 100% output and duct burners off.<sup>5</sup>

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**DEPARTMENT BACT DETERMINATION**

Following are the BACT limits determined for the Calpine project assuming full load. Values for NO<sub>x</sub> and CO are corrected to 15% O<sub>2</sub>. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 20 through 24.

| POLLUTANT                             | CONTROL TECHNOLOGY                                             | BACT DETERMINATION                                                                                                    |
|---------------------------------------|----------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------|
| PM/PM <sub>10</sub> , VE              | Pipeline Natural Gas<br>Good Combustion<br>Inlet Air Filtering | 10 Percent Opacity<br>24.1 lb/hr during DB plus PA<br>9 ppmvd Ammonia Slip                                            |
| SO <sub>2</sub> / SAM                 | Pipeline Natural Gas                                           | 2 grains S / 100 scf                                                                                                  |
| VOC                                   | Pipeline Natural Gas<br>Good Combustion                        | 2.3 ppmvd<br>4.6 ppmvd during DB plus PA                                                                              |
| CO                                    | Pipeline Natural Gas<br>Good Combustion                        | 10 ppmvd – 24 hour block average, or<br>17 ppmvd – 24 hour block average; and<br>10 ppmvd and 45 lb/hr w/o DB plus PA |
| NO <sub>x</sub> (all operating modes) | DLN & SCR                                                      | 3.5 ppmvd (SCR)<br>DB limited to 0.1 lb/MW-hr<br>27.5 lb/hr during DB plus PA                                         |
| PM (cooling tower)                    | High efficiency drift eliminators                              | 0.002% drift loss                                                                                                     |

**RATIONALE FOR DEPARTMENT'S DETERMINATION**

- The Lowest Achievable Emission Rate (LAER) for NO<sub>x</sub> is approximately 2 ppmvd. It has been achieved at a small combustion turbine installation using SCONO<sub>x</sub>.
- EPA Region IV advised that the Department (in a draft BACT) did not present “any unusual site-specific conditions associated with the KUA Cane Island 3 project to indicate that the use of SCR to achieve 3.5 ppmvd would create greater problems than experienced elsewhere at other similar facilities.”<sup>6</sup> The Fish & Wildlife Service has similar comments for Calpine Osprey Energy Center.<sup>9</sup>
- EPA advised FDEP that it intended to appeal the KUA Permit if the Department did not require a NO<sub>x</sub> emissions rate of 3.5 ppmvd when firing natural gas.<sup>7</sup>
- FDEP considered a shorter (3-hour) averaging time for NO<sub>x</sub> compliance, but was ultimately persuaded to provide the higher (24-hour) averaging time due to Calpine’s BACT proposal being the first one submitted in Florida where a low (4.0 ppmvd) emission rate SCR was proposed by the applicant. FDEP intends to issue subsequent BACT Determinations with lower averaging time requirements.
- Uncertainties (and statistical variances) in NO<sub>x</sub> emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O<sub>2</sub> and ambient conditions, etc., are approximately equal to “ultra low NO<sub>x</sub>” limits (2.5-3.5 ppmvd).<sup>8</sup>
- VOC emissions of 2.3 ppm from the combustion turbine by Good Combustion proposed by the applicant are acceptable values determined as BACT. However even lower values have already been achieved by the previous generation DLN 2 combustors on the GE’s 7FA units after tuning. Similar VOC performance is expected with the Westinghouse combustors while firing natural gas.
- The CO concentrations of 10 ppmvd are low, for operation with the duct burner off. This emission rate will be verified on an annual basis via stack test. With the duct burner on, emissions will be less than 20 ppmvd, which is within the range of recent Department BACT determinations for combustion

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turbines alone. However, values as high as 50 ppmvd for 60% - 70% operation will not be authorized for up to 1500 hours annually, as requested by the applicant. The CO limit will be 10 ppmvd on a 24-hour block average, or 17 ppmvd on a weighted daily (24-hour block) average, which incorporates a reasonable allowance for all daily off-normal operations. CEMS will be used for compliance.

- For reference, CO limits for the Lakeland and Tallahassee projects are 25 ppmvd on gas while the limit for the FPL Fort Myers project is 12 ppmvd. Limits for the Santa Rosa Energy Center are 9 ppmvd with the duct burner off and 24 ppmvd with the duct burner on. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO<sub>x</sub>, SO<sub>2</sub>, VOC (ozone) or PM<sub>10</sub>.
- BACT for PM<sub>10</sub> was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM<sub>10</sub> emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT.

**COMPLIANCE PROCEDURES**

| POLLUTANT                           | COMPLIANCE PROCEDURE                                                                                       |
|-------------------------------------|------------------------------------------------------------------------------------------------------------|
| PM/Visible Emissions                | Method 5 (initial test only) and Method 9                                                                  |
| Volatile Organic Compounds          | Method 18, 25, or 25A (initial tests only)                                                                 |
| Carbon Monoxide                     | CEMS plus annual method 10 during operation at capacity without use of duct burners and power augmentation |
| NO <sub>x</sub> 24-hr block average | NO <sub>x</sub> CEMS, O <sub>2</sub> or CO <sub>2</sub> diluent monitor, and flow device as needed         |
| NO <sub>x</sub> (performance)       | Annual Method 20 or 7E                                                                                     |
| Ammonia Slip                        | EPA Method 26A (modified) and Draft Method 206 (Annual)                                                    |

**BACT EXCESS EMISSIONS APPROVAL**

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO<sub>x</sub> or CO standard. These excess emissions periods shall be reported as required in Specific Condition 27 of the Permit. A valid hourly emission rate shall be calculated for each hour in which at least two pollutant concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C. and applicant request].

Excess emissions may occur under the following startup scenarios:

Hot Start: One hour following a HRSG shutdown less than or equal to 8 hours.

Warm Start: Two hours following a HRSG shutdown between 8 and 48 hours.

Cold Start: Four hours following a HRSG shutdown greater than or equal to 48 hours.

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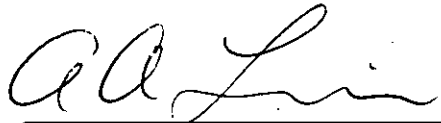
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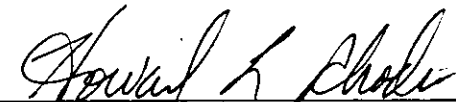
**DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:**

Michael P. Halpin, P.E. Review Engineer *MP Halpin, P.E.*  
A. A. Linero, P.E. Administrator, New Source Review Section  
Cleve Holladay, Meteorologist, New Source Review Section  
Department of Environmental Protection  
Bureau of Air Regulation  
2600 Blair Stone Road  
Tallahassee, Florida 32399-2400

Recommended By:

Approved By:

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

  
Howard L. Rhodes, Director  
Division of Air Resources Management

Date: \_\_\_\_\_

Date: July 3, 2001



**APPENDIX BD**  
**BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)**

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**REFERENCES**

- <sup>1</sup> News Release. Goaline Environmental. Genetics Institute Buys SCONox Clean Air System. August 20, 1999.
- <sup>2</sup> "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.
- <sup>3</sup> Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.
- <sup>4</sup> Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.
- <sup>5</sup> Table A-2, referencing Siemens-Westinghouse. Calpine Osprey Energy Center application received 3-30-2000.
- <sup>6</sup> Letter. Neeley, R. Douglas, EPA Region IV, to Fancy, C.H., FDEP. Draft PSD Permit -- KUA Project. February 2, 1999.
- <sup>7</sup> Letter. Smith, Winston, EPA Region IV, to Rhodes, H.L., FDEP. Proposed KUA Permit. November 8, 1999.
- <sup>8</sup> Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.
- <sup>9</sup> Letter. Porter, Ellen to Linero, A.A., FDEP. Technical Review of Prevention of Significant Deterioration Permit Application For Osprey Energy Center. April 17, 2000.

## Memorandum

## Florida Department of Environmental Protection

---

TO: Howard L. Rhodes

THRU: ~~Clair Fanczy~~  
Al Linero *ay*

FROM: Michael P. Halpin *MPH*

DATE: June 29, 2001

SUBJECT: Calpine – Osprey Energy Center

*Free  
copy*

Attached for approval and signature is a PSD permit for the subject (new) facility. The facility will consist of two Westinghouse “F” frame combustion turbines, each with a supplementally fired HRSG for use with a 200 MW steam turbine. The draft permit was issued over a year ago, as this project was subject to Power Plant Siting and encountered several hurdles.

The permit allows for NO<sub>x</sub> emissions of 3.5 ppmvd on a 24-hour block average (via SCR). Additionally, the permit will require a CEMS for the continuous measurement of CO emissions, which will also be based upon a 24-hour block average. Lastly, although ammonia slip emissions of up to 9 ppmvd are allowed, there are a variety of “triggers” within the permit to ensure that the actual ammonia slip remains below 7 ppmvd.

Emissions of sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently clean pipeline quality natural gas with no fuel oil usage.

The Siting Board met on June 26 and approved the Recommended Order of Judge Johnston. On June 27, OGC informed us that the PSD permit could be issued.

I recommend your approval and signature.

Attachments

/mph



Jeb Bush  
Governor

# Department of Environmental Protection

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

David B. Struhs  
Secretary

February 26, 2003

## CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Benjamin M. H. Borsch, P.E.  
Manager, Safety Health & Environmental  
Calpine Construction Finance Company, L.P.  
Island Center  
2701 N. Rocky Point Drive, Suite 1200  
Tampa, Florida 33607

Re: Extension of Expiration Date of Permit No. PSD-FL-287 (PA00-41)  
Osprey Energy Center

The applicant, Benjamin M. H. Borsch, Manager, Safety Health & Environmental – Calpine, applied on February 17, 2003, to the Department for an extension of the expiration date of PSD permit number PSD-FL-287 for its Osprey Energy Center located at 1501 Derby Avenue, Auburndale, Polk County. The Department has reviewed the request. The expiration date is hereby extended from December 31, 2003 to December 31, 2004 to allow for completion of construction and testing.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department'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 interests will be affected by the agency determination; (c) A statement of how and when 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 indicate; (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 petitioner wishes the agency to take with respect to the agency's proposed action.

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A petition that does not dispute the material facts upon which the Department'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.

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

Mediation is not available in this proceeding.

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

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

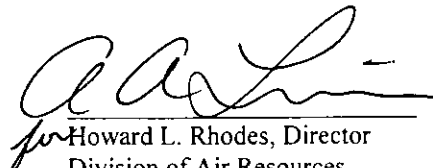
The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will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

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

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this order will not be effective until further order of the Department.

Any party to this permitting decision (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.

  
for Howard L. Rhodes, Director  
Division of Air Resources  
Management

**CERTIFICATE OF SERVICE**

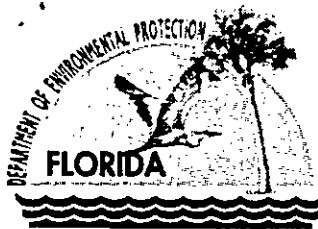
The undersigned duly designated deputy agency clerk hereby certifies that this order was sent by certified mail (\*) and copies were mailed by U.S. Mail before the close of business on 2/27/03 to the person(s) listed:

Mr. Robert K. Alff, Senior VP, Calpine Eastern Corporation \*  
Mr. Benjamin Borsch, Environmental Manager, Calpine \*  
Mr. Gerald Kissel, SWD-DEP  
Mr. Hamilton S. Oven, DEP-Siting  
Mr. Gregg Worley, EPA  
Mr. John Bunyak, NPS

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.

Victoria Gibson / February 27, 2003  
(Clerk) (Date)



Jeb Bush  
Governor

# Department of Environmental Protection

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

Colleen M. Castille  
Secretary

June 18, 2004

## CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Benjamin M. H. Borsch, P.E.  
Manager, Safety Health & Environmental  
Calpine Construction Finance Company, L.P.  
Island Center  
2701 N. Rocky Point Drive, Suite 1200  
Tampa, Florida 33607

Re: Osprey Energy Center, PSD Permit No. PSD-FL-287 (PA00-41)  
Emergency Generator

The applicant, Benjamin M. H. Borsch, Manager, Safety Health & Environmental – Calpine, applied on June 9, 2004, to the Department for a change to PSD permit number PSD-FL-287 for its Osprey Energy Center located at 1501 Derby Avenue, Auburndale, Polk County. The construction permit is set to expire on December 31, 2004 and the applicant has indicated that the plant design requires that the emergency generator (which is not identified as a specific emissions unit, but rather referred to only within the general descriptions of the permit) be low sulfur diesel-fired rather than fired by natural gas. The Department has reviewed the request and finds that the size of the proposed generator (1250 KW) and the maximum heat input rating (14 MMBtu/hr) do not prompt NSPS applicability. Additionally, the applicant further stipulates that the emergency generator will operate less than 500 hours per year, consume less than 32,000 gallons of diesel per year, and is not subject to the Acid Rain Program making it categorically exempt as per 62-210.300(3)(a)20.F.A.C. Based upon these facts, the Department makes the following two changes to the subject permit:

## PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of a nominal 527 megawatt (MW) Combined Cycle plant consisting of: two nominal 170 MW gas-fired, stationary combustion turbine-electrical generators fired solely on natural gas; two supplementally-fired heat recovery steam generators (HRSGs); a nominal 200 MW steam electrical generator; two stacks; an emergency (~~gas-fired~~) generator; a diesel fire pump; two selective catalytic reduction units including ancillary equipment and ammonia storage. The combined cycle plant will achieve approximately 585 megawatts in combined cycle operation during extreme winter peaking conditions. The facility is designated as Osprey Energy Center and will be situated adjacent to the Auburndale Power Partners facility, which is located at 1501 Derby Avenue, Auburndale, Polk County. UTM coordinates are: Zone 17; 421.0 km E; 3103.2 km N.

## FACILITY DESCRIPTION

The proposed Osprey Energy center is a nominal 527 MW combined cycle plant. It will include: two nominal 170 MW gas-fired, stationary combustion turbine-electrical generators fired solely on natural gas; two supplementally-fired heat recovery steam generators (HRSGs); a nominal 200 MW steam electrical generator; two stacks; an emergency (~~gas-fired~~) generator; a diesel fire pump; two selective catalytic reduction units including ancillary equipment and ammonia storage. New major support facilities include a cooling tower, water and wastewater facilities and a transmission line.

Emissions from Osprey Energy Center will be controlled by Dry Low NO<sub>x</sub> (DLN) combustors and selective catalytic reduction (SCR). Pipeline quality natural gas and good combustion practices will be employed to control all pollutants.

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A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 of the Florida Administrative Code.

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

Mediation is not available in this proceeding.

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

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.



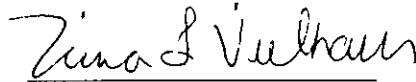
The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will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

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

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this order will not be effective until further order of the Department.

Any party to this permitting decision (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 Vielhauer, Bureau Chief  
Division of Air Resources  
Management

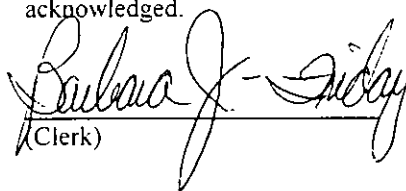
#### CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order was sent by certified mail (\*) and copies were mailed by U.S. Mail before the close of business on 6/18/04 to the person(s) listed:

Mr. Robert K. Alff, Senior VP, Calpine Eastern Corporation \*  
Mr. Benjamin Borsch, Environmental Manager, Calpine \*  
Mr. Gerald Kissel, SWD-DEP  
Mr. Hamilton S. Oven, DEP-Siting  
Mr. Gregg Worley, EPA  
Mr. John Bunyak, NPS

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.

  
(Clerk) 6/18/04  
(Date)

## Memorandum

## Florida Department of Environmental Protection

---

TO: Michael G. Cooke

THRU: Trina Vielhauer   
J. K. Pennington 

FROM: Michael P. Halpin 

DATE: January 7, 2005

SUBJECT: Calpine – Osprey Energy Center  
PSD Permit Modification – Low Load Testing  
DEP File No. 1050334-005 (PSD-FL-287)

Attached is the final permit modification relative to the Osprey Energy Center PSD permit.

This is a permit modification which allows the applicant to perform low load testing on its combined cycle unit for up to 30 days. This was the simplest and most expeditious way to accommodate Calpine's request, which required temporary relief for the emission limits of CO and NO<sub>x</sub>. Of relevance, the relief being sought was insignificant from a PSD perspective.

A public notice was made on December 18, 2004 in the Lakeland Ledger and no comments were received. According to our time clock, the final permit must be issued by January 15<sup>th</sup> and the applicant wishes to begin testing on January 14<sup>th</sup>.

Accordingly, I recommend your approval.

Attachments

/mph



Jeb Bush  
Governor

# Department of Environmental Protection

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

Colleen M. Castille  
Secretary

January 7, 2005

Mr. Benjamin M. H. Borsch, P.E.  
Manager, Safety Health & Environment  
Calpine Corporation  
2701 N. Rocky Point, Suite 1200  
Tampa, Florida 33607

Re: Low load testing, PSD-FL-287  
DEP File Number 1050334-005-AC  
Osprey Energy Center / Polk County

The applicant, Calpine Corporation, applied on December 3, 2004, to the Department for authorization to perform low load testing at its Osprey Energy Center located in Polk County. The request entails providing for the potential of temporary emission increases above the existing emission limits for CO, NO<sub>x</sub> and ammonia slip. Such a request necessitates temporary modifications to PSD permit number PSD-FL-287, allowing for Units 1 and 2 to operate down to loads of at least 30% output (approximately 50 gross megawatts) along with the granting of temporary emission allowances for the purposes of testing and control tuning. In support of the request, Calpine has reviewed test results, for nearly identical Calpine units, and estimates that the following temporary permit changes will be required.

The Department has reviewed the modification request. The referenced permit is hereby temporarily modified as follows:

### III. Emissions Unit(s) Specific Conditions Applicable Standards And Regulations:

#### 20. Nitrogen Oxides (NO<sub>x</sub>) Emissions:

- The concentration of NO<sub>x</sub> in the stack exhaust gas, with the combustion turbine operating, the duct burner on or off, shall not exceed ~~3-5~~ 5.0 ppmvd @15% O<sub>2</sub> on a 24-hr block average. This limit shall apply whether or not the unit is operating with duct burner on and/or in power augmentation mode. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- The emissions of NO<sub>x</sub> shall not exceed 27.5 lb/hr (at 95°F ambient temperature) while operating in the power augmentation mode with the duct burner on, to be demonstrated by annual stack test. [BACT Determination]
- Emissions of NO<sub>x</sub> from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition 29). [Applicant Request, Rule 62-4.070 and 62-204.800(7), F.A.C.]
- The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed ~~9-0~~ 15.0 ppmvd @15% O<sub>2</sub>. The compliance procedures are described in Specific Conditions 29 and 46. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO<sub>x</sub> monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

21. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas shall exceed neither 10 ppmvd @15% O<sub>2</sub> on a 24-hr block average to be demonstrated by CEMS for those days when no valid hour includes the use of duct burner firing, power augmentation or ~~60-~~ less than 70% operation (otherwise, the limit is ~~17~~ 37 ppmvd @15% O<sub>2</sub> on a 24-hr block average to be demonstrated by CEMS); and neither 10 ppmvd @15% O<sub>2</sub> nor 45 lb/hr per unit at

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- 100% output with the duct burner off and no power augmentation to be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing. [BACT, Rule 62-212.400, F.A.C.]
25. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to and shutdowns from combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. Operation below ~~60%~~ 30% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [Rule 62-210.700, F.A.C.].
35. Test Notification: The DEP's Southwest District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance tests. During the "special testing" which is requested herein by Calpine, the DEP's Southwest District Office shall be notified, in writing, at least 72 hours prior to commencement of such testing.
47. The above permit modifications will expire 30 days following the issuance date below. A test report shall be filed with the Department, within 45 days of the expiration of this permit, including reports of all tests conducted as well as Calpine's analysis thereof. Additionally, Calpine shall submit an electronic version of all NO<sub>x</sub> and CO CEMS data as well as a written summary of the data.

All other terms and conditions of this permit remain unchanged. A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., 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.



Michael G. Cooke, Director  
Division of Air Resource  
Management

**CERTIFICATE OF SERVICE**

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (\*) and copies were mailed by U.S. Mail before the close of business on 1/10/05 to the person(s) listed:

Benjamin M. H. Borsch, P.E. \*  
Robert Soich, FDEP SWD  
Gregg Worley, EPA  
John Bunyak, NPS

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.

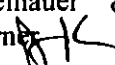
Mary L. Starny 1/10/05  
(Clerk) (Date)

## Memorandum

## Florida Department of Environmental Protection

---

TO: Michael G. Cooke

THRU: Trina Vielhauer   
Jeff Koerner 

FROM: Michael P. Halpin 

DATE: May 9, 2005

SUBJECT: Calpine – Osprey Energy Center  
PSD Permit Modification – Low Load Testing  
DEP File No. 1050334-006 (PSD-FL-287)

Attached is the final permit modification relative to the Osprey Energy Center PSD permit. It is a modification which allows operation below the “2 hours per 24 at 60% output or less” limit established within PSD-FL-287 for each of the two combined cycle units. For informational purposes, the 60% limit was established based upon the Department’s belief that the BACT limits could not be met below that point.

In support of its request, Calpine has provided data, for low load testing, which was performed under permit 1050334-005-AC, granted by the Department on January 7, 2005. This data supports Calpine’s assertion that each combustion turbine unit may be operated at loads above 30% output (approximately 50 megawatts gross) while meeting its existing BACT limits. Accordingly, no increases in emissions are expected as a result of this modification.

A public notice was made on April 23, 2005 in the Lakeland Ledger and no comments were received.

Accordingly, I recommend your approval.

Attachments

/mph



Jeb Bush  
Governor

# Department of Environmental Protection

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

Colleen M. Castille  
Secretary

May 9, 2005

Mr. Benjamin M. H. Borsch, P.E.  
Manager, Safety Health & Environment  
Calpine Corporation  
2701 N. Rocky Point, Suite 1200  
Tampa, Florida 33607

Re: PSD-FL-287 Permit Modification, Low Load Operation  
DEP File Number 1050334-006-AC and PA00-41  
Osprey Energy Center / Polk County

The applicant, Calpine Corporation, applied on February 15, 2005, to the Department for authorization to operate for extended periods at loads lower than those originally authorized (60% output, under PSD-FL-287) at its Osprey Energy Center located in Polk County. In support of its request, Calpine has provided data for low load testing performed under permit 1050334-005-AC, granted by the Department on January 7, 2005. This data supports Calpine's assertion that each combustion turbine unit may be operated at loads above 30% output while meeting its BACT limits.

The Department has reviewed the modification request. The referenced PSD permit is hereby modified as follows:

### III. Emissions Unit(s) Specific Conditions Applicable Standards And Regulations:

21. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas shall exceed neither 10 ppmvd @15% O<sub>2</sub> on a 24-hr block average to be demonstrated by CEMS for those days when no valid hour includes the use of duct burner firing, power augmentation or ~~60-70%~~ operation below 30% excluding periods of start-up and shut-down (otherwise, the limit is 17 ppmvd @15% O<sub>2</sub> on a 24-hr block average to be demonstrated by CEMS); and neither 10 ppmvd @15% O<sub>2</sub> nor 45 lb/hr per unit at 100% output with the duct burner off and no power augmentation to be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing. [BACT, Rule 62-212.400, F.A.C.]
25. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to and shutdowns from combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. Operation ~~below 60%~~ 30% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [Rule 62-210.700, F.A.C.].

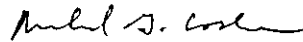
"More Protection, Less Process"

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All other terms and conditions of this permit remain unchanged. A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., 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.



Michael G. Cooke, Director  
Division of Air Resource  
Management

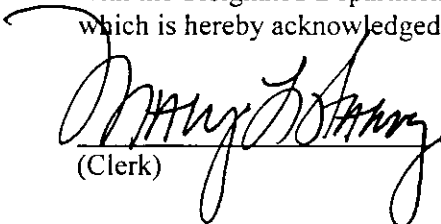
**CERTIFICATE OF SERVICE**

The undersigned duly designated deputy agency clerk hereby certifies that this PSD Permit Modification was sent by certified mail (\*) and copies were mailed by U.S. Mail before the close of business on 5/16/05 to the person(s) listed:

Benjamin M. H. Borsch, P.E. \*  
Gerry Kissel, FDEP SWD  
Buck Oven, PPSO  
Gregg Worley, EPA  
John Bunyak, NPS

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.



(Clerk)

5/16/05  
(Date)



## Memorandum

## Florida Department of Environmental Protection

---

TO: Michael G. Cooke

THRU: Trina Vielhauer   
Jeff Koerner 

FROM: Michael P. Halpin 

DATE: June 27, 2005

SUBJECT: Calpine – Osprey Energy Center  
PSD Permit Modification – Annual Testing Requirements  
DEP File No. 1050334-007, PSD-FL-287 and PA00-41

Attached is the final permit modification relative to the Osprey Energy Center PSD permit. The modification allows for changes to two separate annual testing requirements. The first change allows for annual tests to be conducted at a single set of load conditions rather than two separate sets of conditions, and the second change allows for a different (EPA approved) method for conducting annual ammonia slip tests.

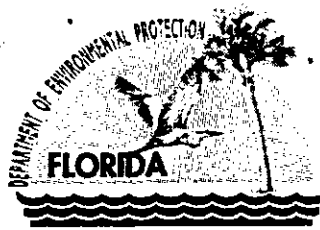
Since there are no increases to emissions as a result of these changes, neither a Determination of Best Available Control Technology (BACT) nor an air quality analysis was required.

A public notice was made on June 10, 2005 in the Lakeland Ledger and no comments were received.

Accordingly, I recommend your approval.

Attachments

/mph



Jeb Bush  
Governor

# Department of Environmental Protection

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

Colleen M. Castille  
Secretary

July 5, 2005

Mr. Benjamin M. H. Borsch, P.E.  
Manager, Safety Health & Environment  
Calpine Corporation  
2701 N. Rocky Point, Suite 1200  
Tampa, Florida 33607

Re: PSD-FL-287 Permit Modification, Annual Testing Requirements  
DEP File Number 1050334-007-AC and PA00-41  
Osprey Energy Center / Polk County

The applicant, Calpine Corporation, applied on May 17, 2005, to the Department for two changes to the annual testing requirements. The requests were for a single annual stack test (rather than two), as well as an alternative (EPA approved) method for testing ammonia slip annually.

The Department has reviewed the modification request. The referenced PSD permit is hereby modified as follows:

### III. Emissions Unit(s) Specific Conditions

#### Applicable Standards And Regulations:

21. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas shall exceed neither 10 ppmvd @15% O<sub>2</sub> on a 24-hr block average to be demonstrated by CEMS for those days when no valid hour includes the use of duct burner firing, power augmentation or operation below 30% excluding periods of start-up and shut-down, ~~nor (otherwise, the limit is 17 ppmvd @15% O<sub>2</sub> on a 24-hr block average for those days when at least one valid hour includes the use of duct burner firing, power augmentation or operation below 30% excluding periods of start-up and shut-down to be demonstrated by CEMS); and neither 10 ppmvd @15% O<sub>2</sub> nor 45 lb/hr per unit at 100% output with the duct burner off and no power augmentation to be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing. [BACT, Rule 62-212.400, F.A.C.]~~
29. Initial (I) performance tests shall be performed by the deadlines in Specific Condition 28. Initial tests shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or change of combustors, if specifically requested by the DEP on a case-by-case basis. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.
  - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
  - EPA reference Method 5, "Determination of Particulate Emissions from Stationary Sources." Initial test only.
  - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
  - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement); Initial test for compliance with 40CFR60 Subpart GG; Initial (only) NO<sub>x</sub> compliance test for the duct burners (Subpart Da) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.

*"More Protection, Less Process"*

*Printed on recycled paper*

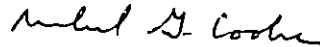
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
- EPA Method 320, "Measurement of vapor phase organic and inorganic emissions by extractive Fourier Transform Infrared (FTIR) Spectroscopy" (I, A); or the following 2 methods:
- EPA Method 26A (modified) for ammonia sample collection (I, A).
- EPA Draft Method 206 for ion chromatographic analysis for ammonia (I, A).

The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O<sub>2</sub>) at the measured lb/hr NO<sub>x</sub> emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition 46.

All other terms and conditions of this permit remain unchanged. A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., 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.



Michael G. Cooke, Director  
Division of Air Resource  
Management

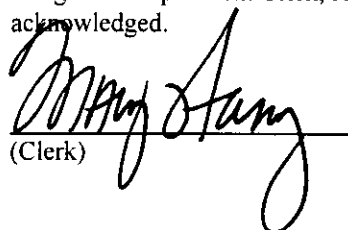
#### CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PSD Permit Modification was sent by certified mail (\*) and copies were mailed by U.S. Mail before the close of business on 7/5/05 to the person(s) listed:

Benjamin M. H. Borsch, P.E. \*  
Joel Smolen, FDEP SWD  
Buck Oven, PPSO  
Gregg Worley, EPA  
John Bunyak, NPS

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.

  
(Clerk)

7/5/05  
(Date)



# Florida Department of Environmental Protection

Bob Martinez Center  
2600 Blair Stone Road  
Tallahassee, Florida 32399-2400

Charlie Crist  
Governor

Jeff Kottkamp  
Lt. Governor

Michael W. Sole  
Secretary

## PERMITTEE

Calpine Corporation Auburndale Energy Complex  
717 Texas Avenue, Suite 1000  
Houston, TX 77002

### *Responsible Official:*

Mr. Jason M. Goodwin  
Director of Environmental Health & Safety

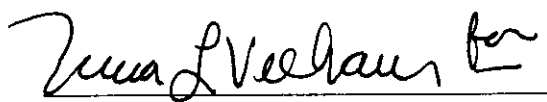
Permit No. 1050221-012-AC  
PSD-FL-185A and PSD-FL-287A  
Auburndale Energy Complex  
Facility ID No. 1050221  
Combustion Turbines  
Revised Capacities

## FACILITY AND LOCATION

This permit revises the original air construction permits (Permit Nos. 1050221-003-AC, 1050221-004-AC (PSD-FL-185) and 1050234-001-AC (PSD-FL-287)) to allow nominal increases to the heat input rates for the four existing combustion turbines. The turbines are installed at the existing Auburndale Energy Complex, which is located at 1501 Derby Avenue (Auburndale Power Plant and Auburndale Peak Energy Center) and 1651 Derby Avenue (Osprey Energy Center) in Auburndale, Florida

## STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations (CFR).

  
Joseph Kahn, Director  
Division of Air Resource Management

2/6/08  
Effective Date

## NOTICE OF FINAL PERMIT

In the Matter of an  
Application for Permit by:

Calpine Corporation  
717 Texas Avenue  
Suite 1000  
Houston, Texas 77002

Authorized Representative:

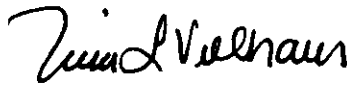
Mr. Jason Goodwin, Director, Environmental Health and Safety

Permit No. 1050221-012-AC  
Auburndale Energy Complex  
Combustion Turbines  
Revised Capacities  
Hardee County, Florida

Enclosed is final air Permit No. 1050221-012-AC (PSD-FL-185A and PSD-FL-287A), which authorizes nominal increases in the heat input rates for the four existing combustion turbines to recognize the actual installed capacities. The combustion turbines are installed at the existing Auburndale Energy Complex, which is located in Polk County at 1501 Derby Avenue (Auburndale Power Plant and Auburndale Peak Energy Center) and 1651 Derby Avenue (Osprey Energy Center) in Auburndale, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S. by filing a Notice of Appeal pursuant to 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 of Appeal must be filed within 30 days from the date this order is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.



Trina Vielhauer, Chief  
Bureau of Air Regulation

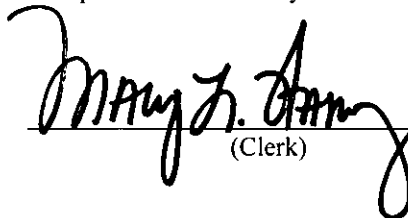
### CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit) was sent by electronic mail with received receipt requested before the close of business on 2/7/08 to the persons listed:

Mr. Jason Goodwin, Calpine Corporation ([jgoodwin@calpine.com](mailto:jgoodwin@calpine.com))  
Ms. Heidi Whidden, Calpine Corporation ([hwhidden@calpine.com](mailto:hwhidden@calpine.com))  
Mr. Thomas Davis, ECT ([tdavis@ectinc.com](mailto:tdavis@ectinc.com))  
Ms. Cindy Zhang-Torres, Southwest District Office ([Cindy.Zhang-Torres@dep.state.fl.us](mailto:Cindy.Zhang-Torres@dep.state.fl.us))  
Ms. Kathleen Forney, EPA Region 4 ([forney.kathleen@epa.gov](mailto:forney.kathleen@epa.gov))

Clerk Stamp

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

  
(Clerk)

2/7/08  
(Date)

## **FINAL DETERMINATION**

---

### **PERMITTEE**

Calpine Corporation  
717 Texas Avenue  
Suite 1000  
Houston, Texas 77002

### **PERMITTING AUTHORITY**

Florida Department of Environmental Protection  
Division of Air Resource Management  
Bureau of Air Regulation, Air Permitting North Section  
2600 Blair Stone Road, MS #5505  
Tallahassee, Florida 32399-2400

### **PROJECT**

Project No. 1050221-012-AC (PSD-FL-185A and PSD-FL-287A)  
Auburndale Energy Complex

The project recognizes the actual installed capacities (maximum heat input rates) for the four existing combustion turbines. The turbines are installed at the existing Auburndale Energy Complex, which is located at 1501 Derby Avenue (Auburndale Power Plant and Auburndale Peak Energy Center) and 1651 Derby Avenue (Osprey Energy Center) in Auburndale, Florida.

### **NOTICE AND PUBLICATION**

The Department distributed the Intent to Issue permit package on December 21, 2007. The applicant published the Public Notice of Intent to Issue in The Ledger on January 5, 2008. The Department received the proof of publication on January 7, 2008.

### **COMMENTS**

No comments on the Draft Permit were received from the public, the Department's Southwest District Office, the EPA Region 4 Office or the applicant.

### **CONCLUSION**

The final action of the Department is to issue the permit as drafted.

## AIR CONSTRUCTION PERMIT REVISIONS

---

### REVISION OF PERMIT NO. 1050221-003-AC (PSD-FL-185)

This permitting action revises the following specific condition for the 156 MW combined cycle combustion turbine (EU-001):

#### **Specific Conditions**

##### Operating Rates

For Condition 5, add the following requirement.

f. Based on the lower heating value (LHV) and International Standards Organization (ISO) conditions, the maximum heat input rate to the combustion turbine is 1,364 MMBtu/hr while firing natural gas with the wet compression system in operation.

### REVISION TO PERMIT NO. 1050221-004-AC (PSD-FL-185)

This permitting action revises the following specific condition for the 120 MW simple cycle combustion turbine (EU-006):

#### **Section 3. Emissions Units Specific Conditions**

3. Permitted Capacity. The maximum heat input to the combustion turbine from firing natural gas shall not exceed ~~1,591~~ 1,776 MMBtu/hour based on the following: 100% base load, a higher heating value (HHV) for natural gas and a compressor inlet air temperature of 32° F. The maximum heat input to the combustion turbine from firing distillate oil shall not exceed ~~1,546~~ 1,726 MMBtu/hour based on the following: 100% base load and a compressor inlet air temperature of 32° F. Heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. [Design; Rule 62-210.200(PTE), F.A.C. and 1050221-004-AC]

### REVISION TO PERMIT NO. 1050234-001-AC (PSD-FL-287)

This permitting action revises the following specific condition for the two 170 MW combined cycle combustion turbines (EU-007 and EU-008):

#### **Section 3. Emissions Units Specific Conditions**

9. Combustion Turbines Capacity: Based on the lower heating value (LHV) of the fuel at ISO conditions, the maximum heat input rate shall not exceed ~~1,669~~ 1,875 MMBtu/hour when firing natural gas without power augmentation. The maximum heat input rate will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be maintained by the plant.

## **APPENDIX II**

### **Title V Permit**



## NOTICE OF FINAL TITLE V AIR OPERATION PERMIT REVISION

### PERMITTEE

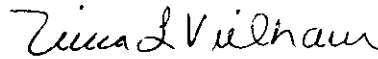
Mr. Jason M. Goodwin  
Calpine Corporation  
717 Texas Avenue, Suite 1000  
Houston, TX 77002

Permit Project No. 1050221-014-AV  
Auburndale Energy Complex  
Hardee County

Enclosed is the Final Permit, No. 1050221-014-AV, for the Title V air operation revision. Project No. 1050221-014-AV revises Title V air operation Permit No. 1050221-013-AV to incorporate the revisions made in air construction Permit No. 1050221-012-AC regarding the maximum heat input rates to emissions units EU-001, EU-006, EU-007, and EU-008, and revises specific conditions in current Title V air operating Permit No. 1050221-013-AV as summarized in the Statement of Basis. The facility is located in Hardee County. This permit renewal is issued pursuant to Chapter 403, Florida Statutes (F.S.). The Proposed Permit was issued February 18, 2008. There were no comments received from Region 4, U.S. EPA, regarding the Proposed Permit.

Any party to this order (permit revision) has the right to seek judicial review of the permit revision pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and, by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Sincerely,



Trina Vielhauer, Chief,  
Bureau of Air Regulation

TLV/jfk/bt

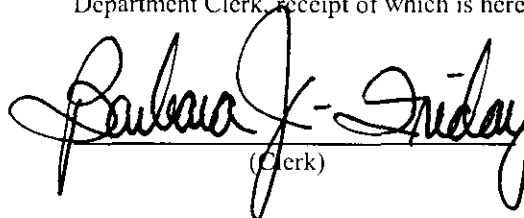
### CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Title V Air Operation Permit Renewal (including the Final Determination and the Final Permit) was sent electronically (with Received Receipt Requested) before the close of business on 4/9/08 to the person(s) listed or as otherwise noted:

Mr. Jason Goodwin, Calpine Corporation ([jgoodwin@calpine.com](mailto:jgoodwin@calpine.com))  
Ms. Heidi Whidden, Calpine Corporation ([hwhidden@calpine.com](mailto:hwhidden@calpine.com))  
Mr. Thomas Davis, ECT ([tdavis@ectinc.com](mailto:tdavis@ectinc.com))  
Ms. Cindy Zhang-Torres, Southwest District Office ([Cindy.Zhang-Torres@dep.state.fl.us](mailto:Cindy.Zhang-Torres@dep.state.fl.us))  
Ms. Kathleen Forney, EPA Region 4 ([forney.kathleen@epa.gov](mailto:forney.kathleen@epa.gov))

Clerk Stamp

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

 4/9/08  
(Clerk) (Date)

## **FINAL DETERMINATION**

Title V Air Operation Permit Revision  
Permit No. 1050221-014-AV  
Calpine Corporation  
Auburndale Energy Complex  
Page 1 of 1

### **I. Comments.**

There were no comments on the proposed permit received from EPA Region 4 during their 45-day review period.

### **II. Conclusion.**

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

## STATEMENT OF BASIS

### Project Information

Permit No. 1050221-014-AV

Title V Air Operation Permit Revision

Auburndale Energy Complex

Facility ID No. 1050221

The entire facility is known as the Auburndale Energy Complex, which consists of two locations, three plants and three owners:

Location: 1501 Derby Avenue, Auburndale, Florida

Auburndale Power Plant owned by the Auburndale Power Partners, L.P.

Auburndale Peak Energy Center owned by the Auburndale Peak Energy Center, LLC.

Location: 1651 Derby Avenue, Auburndale, Florida

Osprey Energy Center owned by the Calpine Construction Finance Company, L.P.

Calpine Operating Services Company, Inc. operates all of the units at the plants. The nominal generating capacity of the plant is 816 megawatts (MW).

### Facility Description

The Auburndale Energy Complex consists of the following emissions units:

| EU No.                        | Brief Description                                                                                                                                                                                                  |
|-------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Auburndale Power Plant        |                                                                                                                                                                                                                    |
| 001                           | Nominal 156 MW combined cycle unit consisting of a nominal 121 MW combustion turbine-electrical generator set, an unfired heat recovery steam generator (HRSG) and a nominal 35 MW steam-electrical generator set. |
| 002                           | Fuel oil storage tanks                                                                                                                                                                                             |
| 003                           | Emergency generators                                                                                                                                                                                               |
| 004                           | Heating units and engines                                                                                                                                                                                          |
| 005                           | Surface coating operations                                                                                                                                                                                         |
| Auburndale Peak Energy Center |                                                                                                                                                                                                                    |
| 006                           | Nominal 120 MW simple cycle combustion turbine-electrical generator set                                                                                                                                            |
| Osprey Energy Center          |                                                                                                                                                                                                                    |
| 007                           | Nominal 170 MW combustion turbine-electrical generator set; part of a combined cycle unit*                                                                                                                         |
| 008                           | Nominal 170 MW combustion turbine-electrical generator set; part of a combined cycle unit*                                                                                                                         |
| 009                           | HRSG equipped with 250 MMBtu per hour duct burner system; part of a combined cycle unit*                                                                                                                           |
| 010                           | HRSG equipped with 250 MMBtu per hour duct burner system; part of a combined cycle unit*                                                                                                                           |
| 011                           | Cooling tower; part of a combined cycle unit*                                                                                                                                                                      |

\* Emissions Units 007 – 011 comprise a nominal 540 MW combined cycle unit consisting of two combustion turbines, two HRSG with duct burner systems, and one shared nominal 200 MW steam-electrical generator set.

The facility also operates other miscellaneous unregulated and insignificant emissions units and activities.

---

## STATEMENT OF BASIS

---

### Regulatory Classifications

The facility is subject to the following primary regulatory classifications and applicable state regulations of the Florida Administrative Code (F.A.C.) as well as the federal New Source Performance Standards (NSPS) in the Code of Federal Regulations (CFR).

- The facility is a Title V major source in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source pursuant to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD).
- The facility operates units subject to Phase II of the federal Acid Rain Program.
- The facility is subject to power plant site certification.
- The facility is not a major source of hazardous air pollutants.
- The four combustion turbines are regulated under the NSPS Subpart A (General Provisions) and Subpart GG (Standards of Performance for Stationary Gas Turbines) in 40 CFR 60.
- The two HRSG with duct burner systems are subject to NSPS Subpart A (General Provisions) and Subpart Da (Standards of Performance for Electric Utility Steam Generating Units) in 40 CFR 60.
- Although the combustion turbines use add-on wet injection systems to control nitrogen oxide (NO<sub>x</sub>) emissions when firing oil, Compliance Assurance Monitoring (CAM) plans are not required because each unit demonstrates compliance with the NO<sub>x</sub> standards by data collected from the continuous emissions monitoring systems.

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

### Project Review

#### Purpose

On September 25, 2007, the applicant submitted an application to revise the original air construction permits (Permit No. 1050221-003-AC / PSD-FL-185 and Permit No. 1050234-001 / PSD-FL-287) and concurrently revise the Title V air operation permit (Permit No. 1050221-013-AV) for the following items.

Section 3, Condition A.2: Revise the maximum heat input to 1,364 MMBtu/hr using a lower heating value (LHV) while firing natural gas with the wet compression system in operation.

Section 3, Condition A.8a: Added language clarifying the definition of a 12 month rolling average.

Section 3, Condition A.12: Added language clarifying compliance test should occur between 90% and 100% of permitted capacity as adjusted for compressor inlet temperature.

Section 3, Condition A.14a: Clarified that annual compliance testing is only required when firing natural gas.

Section 3, Condition A.15 and B.15: Added language to the fuel sulfur monitoring requirements to clarify the methods used must be in accordance with the approved 40 CFR 75 methods.

Section 3, Conditions A.16c, B.12h, and C.14d: Added a condition to clarify CEMS data exclusions when conducting major combustor tuning.

Section 3, Condition B.1: Revise the maximum heat input to 1,776 MMBtu/hr using a higher heating value (HHV) while firing natural gas and 1,726 MMBtu/hr when firing distillate oil. Deleted reference to wet compression system as this operation is no longer applicable.

Section 3, Condition B.2: Deleted reference to wet compression operation as this operation is no longer applicable.

## **STATEMENT OF BASIS**

---

Section 3, Condition B.12a: Deleted language clarifying that operation and maintenance of the NO<sub>x</sub> monitor shall be in accordance with the applicable requirements of 40 CFR 75.

Section 3, Condition B.14d: Added language allowing the annual CO RATA test to be conducted in conjunction with the next required NO<sub>x</sub> RATA when EU-006 operates less than 400 hours per year.

Section 3, Condition B.14e: Added language clarifying the operating rate during compliance testing.

Section 3, Condition C.2: Revise the maximum heat input to 1,875 MMBtu/hr using a LHV while firing natural gas.

Section 3, Condition C.17: Incorporated conditions from Permit No. 1050334-007-AC allowing carbon monoxide (CO) continuous emissions monitoring system (CEMS) data from the annual RATA testing to substitute for annual CO stack test requirements.

Section 3, Condition C.19b: Revised language to clarify ammonia flow rate requirements during periods of NO<sub>x</sub> CEMS downtime or malfunction.

### **Conclusion**

Based on reasonable assurances of compliance provided by the applicant and the Responsible Official's certification of compliance, the Department will issue the Title V air operation permit under the provisions of Chapter 403, Florida Statutes (F.S.) and F.A.C. Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296 and 62-297. The permit authorizes operation of the facility shown on the application and approved drawings, plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

**Title V Air Operation Permit  
Permit No. 1050221-014-AV**

**Facility**

Auburndale Energy Complex  
Facility ID No. 1050221  
Polk County, Florida

**Permittee**

Calpine Construction Finance Company, L.P.  
Auburndale Peaker Energy Center, LLC  
Auburndale Power Partners, L.P.

**Permitting Authority**

Florida Department of Environmental Protection  
Division of Air Resource Management  
Bureau of Air Regulation  
Mail Station #5505  
2600 Blair Stone Road  
Tallahassee, Florida 32399-2400  
Telephone: 850/488-0114  
Fax: 850/921-9533

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# Florida Department of Environmental Protection

Bob Martinez Center  
2600 Blair Stone Road  
Tallahassee, Florida 32399-2400

Charlie Crist  
Governor

Jeff Kottkamp  
Lt. Governor

Michael W. Sole  
Secretary

**Permittee:**

Calpine Corporation  
717 Texas Avenue, Suite 1000  
Houston, TX 77002

Permit No. 1050221-014-AV  
Auburndale Energy Complex  
Facility ID No. 1050221  
Title V Air Operation Permit

**Responsible Official:**

Mr. Jason M. Goodwin  
Director of Environmental Health & Safety

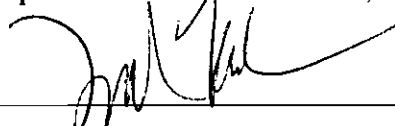
This permit revises the Title V air operation permit for the Auburndale Energy Complex, which is an existing power plant (SIC No. 4911). The entire facility is known as the Auburndale Energy Complex and consists of two locations, three plants and three owners as follows:

- Location: 1501 Derby Avenue, Auburndale, Florida  
Auburndale Power Plant owned by the Auburndale Power Partners, L.P.  
Auburndale Peak Energy Center owned by the Auburndale Peaker Energy Center, LLC.
- Location: 1651 Derby Avenue, Auburndale, Florida  
Osprey Energy Center owned by the Calpine Construction Finance Company, L.P.

Calpine Operating Services Company, Inc. operates all of the units at these plants. The nominal generating capacity of the plant is 816 megawatts (MW). The reference UTM Coordinates are Zone 17, 420.8 km East and 3103.3 km North.

The 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 permittees are hereby authorized to operate the plants in accordance with the terms and conditions of this permit as well as the application, approved drawings, plans, and other documents, attached hereto or on file with the permitting authority.

**Effective Date:** January 1, 2008  
**Revision Effective Date:** April 4, 2008  
**Renewal Application Due Date:** April 1, 2012  
**Expiration Date:** December 31, 2012

  
\_\_\_\_\_  
Joseph Kahn, Director  
Division of Air Resource Management



## SECTION I. FACILITY INFORMATION.

### Subsection A. Facility Description.

Calpine Operating Services Company, Inc. operates three existing power plants that comprise the Auburndale Energy Complex. The plants consist of a combination of simple cycle and combined cycle combustion turbines. The nominal generating capacity of the Auburndale Energy Complex is 816 megawatts (MW).

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility operates units subject to Phase II of the federal Acid Rain Program.
- The facility is a Title V major source in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source pursuant to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD).
- The facility is subject to power plant site certification.

### Subsection B. Summary of Emissions Units.

The Auburndale Energy Complex consists of the following emissions units:

| EU No.                        | R/U <sup>a</sup> | Brief Description                                                                                                                                                                                                             |
|-------------------------------|------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Auburndale Power Plant        |                  |                                                                                                                                                                                                                               |
| 001                           | R                | Nominal 156 MW combined cycle unit consisting of a combustion turbine-electrical generator set rated at 121.5 MW, an unfired heat recovery steam generator (HRSG) and a nominal 52 MW steam turbine-electrical generator set. |
| 002                           | U                | Fuel oil storage tanks                                                                                                                                                                                                        |
| 003                           | U                | Emergency generators                                                                                                                                                                                                          |
| 004                           | U                | Heating units and engines                                                                                                                                                                                                     |
| 005                           | U                | Surface coating operations                                                                                                                                                                                                    |
| Auburndale Peak Energy Center |                  |                                                                                                                                                                                                                               |
| 006                           | R                | Nominal 120 MW simple cycle combustion turbine-electrical generator set                                                                                                                                                       |
| Osprey Energy Center          |                  |                                                                                                                                                                                                                               |
| 007                           | R                | Nominal 170 MW combined cycle combustion turbine-electrical generator set <sup>b</sup>                                                                                                                                        |
| 008                           | R                | Nominal 170 MW combined cycle combustion turbine-electrical generator set <sup>b</sup>                                                                                                                                        |
| 009                           | R                | HRSG equipped with 250 MMBtu per hour gas-fired duct burner system <sup>b</sup>                                                                                                                                               |
| 010                           | R                | HRSG equipped with 250 MMBtu per hour gas-fired duct burner system <sup>b</sup>                                                                                                                                               |
| 011                           | U                | Cooling tower                                                                                                                                                                                                                 |

- a. "R" means regulated and "U" means unregulated.
- b. Emissions Units 007 – 011 comprise a nominal 540 MW combined cycle unit consisting of two combustion turbines, two HRSG with duct burner systems, and one shared nominal 200 MW steam-electrical generator set.

The facility also operates other miscellaneous unregulated and insignificant emissions units and activities. The four combustion turbines are subject to: Phase II of the federal Acid Rain Program; the New Source Performance Standards (NSPS) in Subpart A (General Provisions) of 40 CFR 60; and NSPS Subpart GG (Standards of Performance for Stationary Gas Turbines) in 40 CFR 60. The two HRSG equipped with duct burners are subject to NSPS Subpart Da (Standards of Performance for Electric Utility Steam Generating Units) in 40 CFR 60.

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

## SECTION 2. FACILITY-WIDE CONDITIONS

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The following conditions apply facility-wide.

1. Appendices. The Appendices identified in the Table of Contents and attached to this permit are an enforceable part of the permit unless otherwise indicated.
2. Effective Date. 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.]
3. 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. *{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2 & 3, F.A.C. [Rules 62-213.440(3) and 62-213.900, F.A.C.]}*
4. EPA. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency (EPA) 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 30303-8960. The telephone number is 404/562-9155 and facsimile number is 404/562-9163.
5. Compliance Authority. The permittee shall submit all compliance related notifications and reports required of this permit to the Southwest District Office of the Florida Department of Environmental Protection (Department) at 13051 N. Telecom Parkway, Temple Terrace, Florida 33637. The telephone number is 813/632-7600 and facsimile number is 813/632-7665.
6. 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.]
7. Source Obligation. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification. [Rule 62-212.400(12)(b), F.A.C.]
8. Annual Operating Report. The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), F.A.C.]
9. Records Retention. All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]

### SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

#### Subsection A. Combined Cycle Combustion Turbine

This section addresses the following emissions unit.

| EU No.                 | Brief Description                                                                                                                                                                                                                                                                                                                           |
|------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Auburndale Power Plant |                                                                                                                                                                                                                                                                                                                                             |
| 001                    | Nominal 156 MW combined cycle unit consisting of a combustion turbine-electrical generator set rated at 121.5 MW, an unfired heat recovery steam generator (HRSG) and a steam turbine-electrical generator set rated at 52 MW. NO <sub>x</sub> emissions are controlled by steam injection and selective catalytic reduction (SCR) systems. |

*{Permitting Note: This emissions unit is regulated under: Acid Rain, Phase II; NSPS Subpart A (General Provisions) and NSPS Subpart GG (Stationary Gas Turbines) in 40 CFR 60; and Rule 212.400(PSD), F.A.C.}*

#### ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

**A.1 Authorized Fuels.** Only natural gas or distillate oil with a maximum sulfur content of 0.05% by weight shall be fired in the combustion turbine. [Rule 62-210.200(PTE), F.A.C. and PSD-FL-185]

**A.2 Permitted Capacity.** Based on the lower heating value (LHV) of each fuel and International Standards Organization (ISO) conditions, the maximum heat input rate to the combustion turbine is 1214 MMBtu/hour while firing natural gas with the wet compression system off or 1,364 MMBtu/hr while firing natural gas with the wet compression system in operation and 1170 MMBtu/hour while firing distillate fuel oil. [Rule 62-210.200(PTE), F.A.C., 1050221-012-AC and PSD-FL-185A]

**A.3 Hours of Operation.** This emissions unit is allowed to operate continuously (8760 hours/year). The total hours of operation of the combustion turbine while firing distillate fuel oil shall not exceed 400 hours/year. [Rule 62-210.200(PTE), F.A.C. and PSD-FL-185]

**A.4 Wet Compression System.** Operation of the wet compression system is approved for use on Unit 1 during any periods at which the ambient temperature is above 60° F. Use of the wet compression system is limited to periods during the firing of natural gas only. [1050221-005-AC]

#### EMISSION LIMITATIONS AND STANDARDS

*{Permitting Note: Unless otherwise specified, the averaging time for an emissions standard is based on the specified averaging time of the applicable test method.}*

**A.5 VE Standards.** Visible emissions from the combustion turbine shall not exceed 10% opacity at full load (i.e. 156MW) and 20% opacity at loads other than full load. [Rule 62-212.400(PSD), F.A.C. and PSD-FL-185]

**A.6 PM<sub>10</sub> Standards.** PM<sub>10</sub> emissions shall not exceed the following:

- a. *Natural Gas:* 0.0134 lb/MMBtu; 10.5 lb/hour; and 46 tons/year.
- b. *Distillate Oil:* 0.0472 lb/MMBtu; 36.8 lb/hour; and 7.4 tons/year.

[Rule 62-212.400(PSD), F.A.C. and PSD-FL-185]

**A.7 SO<sub>2</sub> Standards.** SO<sub>2</sub> emissions shall not exceed the following:

- a. *Natural Gas:* 40.0 lb/hour; and 175.2 tons/year.
- b. *Distillate Oil:* use of distillate oil with a maximum sulfur content of 0.05 % by weight; 70.0 lb/hour; and 14 tons/year.

[Rule 62-212.400(PSD), F.A.C. and PSD-FL-185]

**A.8 NO<sub>x</sub> Standards.** NO<sub>x</sub> emissions shall not exceed the following:

- a. *Natural Gas:* 15 ppmvd corrected to 15% oxygen based on a 24-hour block average as defined below; 9 ppmvd corrected to 15% oxygen based on a 12-month rolling equivalent average as defined below; 78.6

## SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

### Subsection A. Combined Cycle Combustion Turbine

lb/hour; and 177 tons/year based on a 12-month rolling total for the combined total of natural gas and distillate fuel oil firing.

- b. *Distillate Oil*: 42 ppmvd corrected to 15% oxygen based on a 24-hour block average; 230.0 lb/hour; 46 tons/year; and 177 tons/year based on a 12-month rolling total for the combined total of natural gas and distillate fuel oil firing.
- c. *Calculation of 24-hour Block Averages*: At the same time each day, a 24-hour block average shall be calculated for the monitored operating hours in the previous 24-hour period. The 24-hour block average shall be determined by summing the hourly average NO<sub>x</sub> concentrations for all valid monitored operating hours and dividing by the number of hourly average NO<sub>x</sub> concentrations in the previous 24-hour period. A monitored operating hour is each hour in which fuel is fired in the combustion turbine and at least two CEMS emission measurements are recorded at least 15 minutes apart. The CEMS data taken during periods of startup, shutdown, or malfunction as defined in Rules 62-210.200 and 62-210.700 F.A.C., when fuel is not fired in the unit, or during CEMS quality assurance checks or when the CEMS is out of control, shall be excluded from the 24-hour block average.
- d. *Calculation of 12-Month Rolling Totals*: For the annual (tons/year) emissions limits of NO<sub>x</sub>, measurements shall be in pounds (converted to tons) and be based on a 12-month rolling total starting at the first day of each calendar month. Each monthly total shall be calculated by adding the pounds per day for each valid operating day (all fuels) within the calendar month. This monthly total shall be combined with the emissions from the previous valid 11 calendar months and shall comprise a 12-month rolling total.
- e. *Calculation of the 12-Month Rolling NO<sub>x</sub> Average*: To demonstrate compliance with the NO<sub>x</sub> limit of 9 ppmvd corrected to 15% oxygen based on a 12-month rolling average, measurements shall be in "ppmvd corrected to 15% oxygen" and be based on a 12-month rolling average starting at the first day of each calendar month. Each monthly average shall be calculated by adding each valid gas firing 24-hour block average (as determined above) from valid operating days within the calendar month. This monthly average shall be combined with the emissions from the previous valid 11 calendar months and shall comprise a 12-month rolling average. In order to convert each 12-month rolling average to an annual equivalent limit, the following formula shall be utilized:

$$\text{ppmvd}_e = (\text{ppmvd}_a) (\text{hours}_g / 8760)$$

Where:

ppmvd<sub>e</sub> = the equivalent annual NO<sub>x</sub> average (ppmvd corrected to 15% oxygen)

ppmvd<sub>a</sub> = the measured (CEMS) 12-month rolling NO<sub>x</sub> average (ppmvd corrected to 15% oxygen) for firing only natural gas

hours<sub>g</sub> = 12-month rolling total valid hours of operation combusting natural gas

[Rule 62-212.400(PSD), F.A.C., PSD-FL-185, 1050221-004-AC, and 1050221-010-AC]

#### A.9 VOC Standards. VOC emissions shall not exceed the following:

- a. *Natural Gas*: 6.0 lb/hour; and 26.3 tons/year.
- b. *Distillate Oil*: 10.0 lb/hour; and 2.0 tons/year.

[Rule 62-212.400(PSD), F.A.C. and PSD-FL-185]

#### A.10 CO Standards. CO emissions shall not exceed the following:

- a. *Natural Gas*: 21 ppmvd at minimum load; 15 ppmvd at base load; 43.5 lb/hour; and 190.5 tons/year.
- b. *Distillate Oil*: 25 ppmvd; 73.0 lb/hour; and 14.6 tons/year.

[Rule 62-212.400(PSD), F.A.C. and PSD-FL-185]

## SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

### Subsection A. Combined Cycle Combustion Turbine

#### EXCESS EMISSIONS

**A.11 Excess Emissions.** 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. Additionally, the permittee's record keeping for the NO<sub>x</sub> emissions caps (TPY) on EU-001 and EU-006 shall be in full agreement with publicly available data on EPA's Acid Rain website which includes all documented exclusions reported to the Department in a quarterly report. However these emissions will be excluded for compliance demonstration. *{Permitting note: Rule 62-210.700(Excess Emissions), F.A.C. cannot vary any requirement of a NSPS or NESHAP provision.}* [Rule 62-210.700(1), F.A.C. and 1050221-010-AC]

#### COMPLIANCE TESTING

**A.12 Testing Requirements.** This emissions unit shall operate between 90% and 100% of permitted capacity during the compliance tests as adjusted for compressor inlet temperature (See attached W501D5 ECONOPAC SYSTEM PERFORMANCE GRAPH.) [Chapter 62-297, F.A.C.]

**A.13 Test Methods.** As required, the following test methods shall be used to determine emissions.

| Method | Description of Method and Comments                                                                                                                                                                                                                               |
|--------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1-4    | Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content                                                                                                                                                                                      |
| 5      | Determination of Particulate Matter Emissions                                                                                                                                                                                                                    |
| 7E     | Determination of Nitrogen Oxide Emissions from Stationary Sources                                                                                                                                                                                                |
| 9      | Visual Determination of the Opacity of Emissions from Stationary Sources                                                                                                                                                                                         |
| 10     | Determination of Carbon Monoxide Emissions from Stationary Sources                                                                                                                                                                                               |
| 18     | Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) {Note: Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions, if specifically requested.}           |
| 19     | Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates {Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.} |
| 20     | Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines                                                                                                                                                              |
| 25A    | Method for Determining Gaseous Organic Concentrations (Flame Ionization)                                                                                                                                                                                         |

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A; 40 CFR 60.334; PSD-FL-185; 1050221-004-AC; and 1050221-010-AC]

**A.14 Frequency of Compliance Tests:** The permittee shall conduct tests on the combustion turbine system to demonstrate compliance with the applicable emissions standards in accordance with the following frequencies.

- Annual Tests:** During each federal fiscal year (October 1 - September 30), the permittee shall have a formal compliance test conducted for CO and visible emissions. Compliance testing is only required during the combustion of natural gas fuel, which is the primary fuel.
- Annual Tests:** During each federal fiscal year (October 1 - September 30), the permittee shall have a formal compliance test conducted for CO and visible emissions. If distillate is fired for more than 400 hours, an annual compliance test shall also be conducted for PM/PM<sub>10</sub> emissions while firing distillate oil.
- Tests Prior to Renewal:** The permittee shall conduct a compliance test that demonstrates compliance with

## SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

### Subsection A. Combined Cycle Combustion Turbine

the applicable emission limiting standards prior to obtaining a renewed operation permit for CO and VOC. Compliance testing is only required during the combustion of natural gas fuel, which is the primary fuel. 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. *{Permitting Note: Continuous compliance with the NO<sub>x</sub> emissions standards is demonstrated with CEMS data.}*

- d. *Exceptions:* Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once in each 5-year period, coinciding with the term of its air operation permit.

[40 CFR 60.334, PSD-FL-185, 1050221-004-AC and 1050221-010-AC]

### MONITORING REQUIREMENTS

**A.15 Fuel Sulfur Monitoring.** The permittee shall determine compliance with the sulfur content standard of 0.05% by weight as follows: ASTM D129-91, D1552-90, D2280-71, D2880-96, D2622-92, D4292, D4294-90, D5453, the latest editions or in accordance with approved 40 CFR Part 75 methods. The permittee shall determine compliance with the fuel sulfur content of gaseous fuels as follows: ASTM D1072-80/90/94, D3031-81/86, D3246-81/92, D4084-82/94, D4468-85, D5504-94, the latest editions or in accordance with approved 40 CFR Part 75 methods. The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator. [40 CFR 60.335 and PSD-FL-185]

**A.16 NO<sub>x</sub> CEMS.** In accordance with Performance Specification 2 in Appendix B of 40 CFR 60, the permittee shall install, calibrate, maintain and operate a CEMS in the stack to measure and record the NO<sub>x</sub> emissions from this unit to demonstrate compliance with the applicable emissions standards. Quality assurance procedures must conform to the applicable sections of Appendix F in 40 CFR 60.

- a. For purposes of demonstrating compliance with the NO<sub>x</sub> mass emission limits (lb/hr and tons/year), NO<sub>x</sub> and diluent concentrations shall be determined by one of the following methods: EPA Method 20 conducted between 90% and 100% of permitted maximum capacity only; continuous monitoring data collected during the relative accuracy test assessment conducted pursuant to Section 7 in Performance Specification 2 of Appendix B, 40 CFR 60; or EPA Method 7E with either EPA Method 3 or 3A in Appendix A of 40 CFR 60.
- b. The NO<sub>x</sub> CEMS shall be used to demonstrate continuous compliance with the NO<sub>x</sub> emission limit (24-hour block average concentration limit).
- c. **CEMS Data Exclusion – Combustor Tuning.** CEMS data collected during initial or other major combustor tuning sessions shall be excluded from the CEMS compliance demonstration for short term emission standards provided the tuning session is performed in accordance with the manufacturer's specifications. All valid emissions data shall be used to demonstrate compliance with annual emissions caps. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Department's Southwest District Compliance Authority with advance notice that details the activity and proposed tuning schedule. The notice shall be by telephone, facsimile transmittal, or electronic mail. [Rules 62-4.070(3), 62-212.400(PSD), F.A.C., 62-210.700(5) F.A.C. and PSD-FL-185A]

[Rule 62-212.400(PSD), F.A.C. and PSD-FL-185]

### RECORD KEEPING AND REPORTING REQUIREMENTS

**A.17 Fuel Records.** Sulfur and lower heating value of the fuel being fired in the combustion turbine shall be based on a weighted 12-month rolling average from fuel delivery receipts. The records of distillate oil usage shall be kept by the permittee for a 5-year period. For SO<sub>2</sub>, periods of excess emissions shall be reported if the fuel being fired exceeds 0.05% sulfur by weight. [Rules 62-212.400(PSD) and 62-213.440(1)(b), F.A.C.; and PSD-

### SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

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#### Subsection A. Combined Cycle Combustion Turbine

FL-185]

**A.18** Common Conditions. See Appendix C of this permit for additional generic record keeping, reporting and notification requirements. [Chapters 62-4, 62-210, 62-296 and 62-297]

#### OTHER REQUIREMENTS

**A.19** NSPS Provisions. The combustion turbine is subject to the applicable requirements of Subpart A (General Provisions) and Subpart GG (Stationary Gas Turbine) in 40 CFR 60. See Appendices D and F of this permit.

## SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

### Subsection B. Simple Cycle Combustion Turbine

This section addresses the following emissions units.

| EU No.                        | Brief Description                                                                                                                                                                                                                                                                                                                                                                                                                                                         |
|-------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Auburndale Peak Energy Center |                                                                                                                                                                                                                                                                                                                                                                                                                                                                           |
| 006                           | Nominal 120 MW simple cycle combustion turbine-electrical generator set consisting of a Siemens Westinghouse Model No. 501D5A unit. The primary fuel is natural gas and distillate oil is fired as a restricted alternate fuel. Water injection is used to control NO <sub>x</sub> emissions. The simple cycle unit operates during periods of peak power demands and is expected to operate near permitted capacity for approximately 20% to 25% of the permitted hours. |

*{Permitting Note: This emissions unit is regulated under: Phase II of the federal Acid Rain Program; NSPS Subpart A (General Provisions) and NSPS Subpart GG (Stationary Gas Turbines) in 40 CFR 60; and Rule 212.400(PSD Avoidance), F.A.C.}*

#### ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

**B.1 Permitted Capacity.** The maximum heat input to the combustion turbine from firing natural gas shall not exceed 1,776 MMBtu/hour based on the following: 100% base load, a higher heating value (HHV) for natural gas and a compressor inlet air temperature of 32° F. The maximum heat input to the combustion turbine from firing distillate oil shall not exceed 1,726 MMBtu/hour based on the following: 100% base load and a compressor inlet air temperature of 32° F. Heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. [Design; Rule 62-210.200(PTE), F.A.C.; and 1050221-004-AC]

#### **B.2 Authorized Fuels.**

- a. The combustion turbine shall fire only natural gas with maximum sulfur content of 2 grains of sulfur per 100 dry standard feet of gas (monthly average) or distillate oil with a maximum sulfur content of 0.05% by weight. [Rules 62-210.200(PTE), F.A.C. and 1050221-004-AC]
- b. The combustion turbine shall fire no more than 2,227,400 MMBtu of natural gas during any consecutive 12-month period (equivalent to approximately 1400 hours/year at base load). The total hours of operation of the combustion turbine while firing distillate fuel oil shall not exceed 400 hours during any consecutive 12-month period. The permittee shall install, calibrate, operate and maintain a monitoring system to measure and accumulate the following for each fuel fired: quantity, heat input rate and hours of operation. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; 1050221-004-AC; and 1050221-006-AC]

#### **B.3 Allowable Operation.**

- a. The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation, nor the permitted short and long-term emission limits allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD non-applicability determination and resulted in the emission standards specified in this permit. Specifically, these restrictions eliminated several control alternatives based on technical as well as regulatory considerations. For any request to modify this emission unit in any way (whether a physical or operational modification, including a change in the allowable hours of operation or heat input, or to alter any short or long-term emission) the permittee shall submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. Alternately, the permittee shall submit a determination of PSD applicability for proposed permit changes, which the Department shall consider in making its determination. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and 1050221-004-AC]
- b. The permittee is authorized to, tune, operate and maintain one new combustion turbine with electrical generator set (Siemens/Westinghouse Model 501D5A). The system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize permitted pollutant emissions. The unit is designed to produce a maximum 135 MW of electrical power. [Rule 62-212.400, F.A.C. (PSD Avoidance), 1050221-004-AC]



### SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

#### Subsection B. Simple Cycle Combustion Turbine

- c. The permittee shall calibrate, tune, operate, and maintain a water injection system for the unit. The system shall be designed and operated so as to ensure that NO<sub>x</sub> emissions do not exceed 25.0 ppmvd corrected to 15% oxygen while burning natural gas and 42.0 ppmvd corrected to 15% oxygen when burning oil. [Rule 62-212.400, F.A.C. (PSD Avoidance), 1050221-004-AC]

#### EMISSION LIMITATIONS AND STANDARDS

- B.4** VE Standard. Visible emissions shall not be equal to or greater than 20% opacity. [Rule 62.296.320(4)(b)1, F.A.C. and 1050221-004-AC]
- B.5** PM/PM<sub>10</sub> Standards. Particulate matter emissions shall not exceed 2.9 lb/hour when firing natural gas and 58.5 lb/hour when firing distillate oil. [Rule 62-212.400(PSD Avoidance), F.A.C and 1050221-004-AC]
- B.6** SO<sub>2</sub> Standards. Sulfur dioxide emissions shall be controlled by the firing of: natural gas with a maximum sulfur content of 2 grains of sulfur per 100 dry standard feet of gas (monthly average); and distillate oil with a maximum sulfur content of 0.05% by weight and 74.9 lb/hour. [Rule 62-4.070(3), F.A.C. and 1050221-004-AC]
- B.7** NO<sub>x</sub> Standards. Nitrogen oxides emissions shall not exceed: 25.0 ppmvd corrected to 15% oxygen based on a 24-hour block average when firing natural gas; 42.0 ppmvd corrected to 15% oxygen based on a 24-hour block average when firing distillate oil; and 115 tons/year based on a 12-month rolling total. Compliance with the NO<sub>x</sub> BACT standard does not require correction to ISO conditions. [Rule 62-212.400 (PSD Avoidance), F.A.C. and 1050221-004-AC]
- B.8** VOC Standards. Volatile organic compound emissions shall not exceed 4.0 ppmvd corrected to 15% oxygen when firing natural gas and 5.0 ppmvd corrected to 15% oxygen firing distillate fuel oil. [Rule 62-4.070(3), F.A.C. and 1050221-004-AC]
- B.9** CO Standard. Carbon monoxide emissions shall not exceed: 10 ppmvd corrected to 15% oxygen at base load (24-hour average) and 99 tons/year based on a 12-month rolling total while burning all fuels. [Rule 62-212.400(PSD Avoidance), F.A.C. and 1050221-004-AC]

#### EXCESS EMISSIONS

*{Permitting Note: Rule 62-210.700(Excess Emissions), F.A.C. cannot vary any requirement of a NSPS or NESHAP provision.}*

- B.10** Excess Emissions Allowed: Providing the permittee adheres to best operational practices to minimize the amount and duration of excess emissions, the following conditions shall apply:
- a. During startup and shutdown, visible emissions excluding water vapor may exceed 20% opacity for up to 2 hours in any 24-hour period.
  - b. During all startups, shutdowns, and malfunctions, the CEMS shall monitor and record emissions. Monitoring data exclusions shall be accordance with Condition B.11 of this permit.
  - c. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report. [Rules 62-210.700(1),(5), 62-4.130, F.A.C. and 1050221-004-AC]

#### MONITORING REQUIREMENTS

- B.11** CMS for Water-to-Fuel Ratio. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG and using water injection to control NO<sub>x</sub> emissions shall install and operate a continuous monitoring system (CMS) to monitor and record the fuel consumption and the ratio of water-to-fuel being fired in the turbine. This system shall be accurate to within  $\pm 5.0$  percent and shall be approved by the Administrator. This system shall be used as a backup to the required CEMS. [Rule 62-212.400(PSD), F.A.C. and 1050221-004-AC]
- B.12** CO and NO<sub>x</sub> CEMS. The owner or operator shall calibrate, maintain, and operate a CEMS in the exhaust

## SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

### Subsection B. Simple Cycle Combustion Turbine

stack of this emissions unit to measure and record the emissions of NO<sub>x</sub> and CO from the emissions units, and the oxygen (O<sub>2</sub>) content of the flue gas at the location where NO<sub>x</sub> and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEMS shall be used to demonstrate compliance with the emission limits for NO<sub>x</sub> and CO within this permit.

- a. The NO<sub>x</sub> monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. Annual RATA tests required for the NO<sub>x</sub> monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The permittee shall conduct an annual RATA test at 100% output in accordance with the applicable CEMS requirements.
- b. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The O<sub>2</sub> monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The span for the CO monitor shall not be greater than 100 ppmvd corrected to 15% oxygen. The RATA tests required for the oxygen monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60. The span for the oxygen monitor shall not be greater than 21%.
- c. For purposes of determining compliance with the NO<sub>x</sub> emission limits based on a 24-hour block average, missing data shall not be substituted pursuant to 40 CFR 75. Instead the block average shall be determined using the remaining hourly data in the 24-hour block. However, the permittee's record keeping for the EU-006 NO<sub>x</sub> emissions caps (tons/year) shall be in full agreement with data submitted for inclusion on EPA's Acid Rain website which includes all documented exclusions reported to the Department in a quarterly report. The permittee may exclude start up, shutdown, and Part 75 missing data from the ppmvd calculations. However, this data will need to be recorded for the tons/year calculations for netting purposes and as required by the Acid Rain website.
- d. The CO, NO<sub>x</sub> and O<sub>2</sub> data shall be recorded by the CEMS during episodes of startup, shutdown and malfunction. No valid monitoring data shall be excluded from the mass-based (tons/year) CO and NO<sub>x</sub> emissions limits. Monitoring data collected during startup, shutdown and malfunctions may be excluded in accordance with the following conditions when determining compliance with concentration-based (ppmvd) CO and NO<sub>x</sub> emissions limits. CO and NO<sub>x</sub> emissions data recorded during these episodes may be excluded from the 24-hour block average calculated to demonstrate compliance with the emission limits of this permit as provided in this paragraph. Periods of data excluded for startup and shutdown shall not exceed two hours in any block 24-hour period. Periods of data excluded for malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all startup, shutdown or malfunction episodes shall not exceed four hours in any 24-hour block period. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.
- e. The 24-hour block averages are calculated as follows: starting at midnight of each operating day, a 24-hour block average shall be calculated from 24 valid hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for

## SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

### Subsection B. Simple Cycle Combustion Turbine

more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. Monitoring data shall be excluded from the 24-hour block average for the following periods: startup, shutdown, or malfunction as defined in Rules 62-210.200 and 62-210.700, F.A.C.; when fuel is not fired in the unit; CEMS quality assurance checks; or when the CEMS is out of control.

**f.** For the annual (tons/year) emissions limits of CO and NO<sub>x</sub>, measurements shall be in pounds (converted to tons) and be based on a 12-month rolling total starting at the first day of each calendar month. Each monthly total shall be calculated by adding the pounds per day for each valid operating day (all fuels) within the calendar month. This monthly total shall be combined with the emissions from the previous valid 11 calendar months and shall comprise a 12-month rolling total.

**g.** Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance. When requested by the Department, the CEMS emission rates for NO<sub>x</sub> on this unit shall be corrected to ISO conditions to demonstrate compliance with the NO<sub>x</sub> standard established in 40 CFR 60.332. Data collected from the NO<sub>x</sub> CEMS shall be used to report excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

**h.** CEMS Data Exclusion – Combustor Tuning. CEMS data collected during initial or other major combustor tuning sessions shall be excluded from the CEMS compliance demonstration for short term emission standards provided the tuning session is performed in accordance with the manufacturer's specifications. All valid emissions data shall be used to demonstrate compliance with annual emissions caps. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Department's Southwest District Compliance Authority with advance notice that details the activity and proposed tuning schedule. The notice shall be by telephone, facsimile transmittal, or electronic mail. [Rules 62-4.070(3), 62-212.400(PSD), F.A.C., 62-210.700(5) F.A.C. and PSD-FL-185A]

[Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.; 1050221-004-AC; Subparts B, C, F and G in 40 CFR Part 75; Appendix A, B and F of 40 CFR 60; Subparts A and GG in 40 CFR 60]

### COMPLIANCE TESTING

**B.13 Test Methods.** As required, the following test methods shall be used to determine emissions.

| Method | Description of Method and Comments                                                                                                                                                                                                                        |
|--------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1-4    | Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content                                                                                                                                                                               |
| 7E     | Determination of Nitrogen Oxide Emissions from Stationary Sources                                                                                                                                                                                         |
| 5      | Determination of Particulate Matter Emissions                                                                                                                                                                                                             |
| 9      | Visual Determination of the Opacity of Emissions from Stationary Sources                                                                                                                                                                                  |
| 10     | Determination of Carbon Monoxide Emissions from Stationary Sources                                                                                                                                                                                        |
| 18     | Measurement of Gaseous Organic Compound Emissions (Gas Chromatography)<br>{Note: Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions, if specifically requested.} |

### SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

#### Subsection B. Simple Cycle Combustion Turbine

| Method | Description of Method and Comments                                                                                                                                                                                                                                     |
|--------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 19     | Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates {Note: Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.} |
| 20     | Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines                                                                                                                                                                    |
| 25A    | Method for Determining Gaseous Organic Concentrations (Flame Ionization)                                                                                                                                                                                               |

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A; 40 CFR 60.334; and 1050221-004-AC]

**B.14 Frequency of Compliance Tests.** The permittee shall conduct the following compliance tests:

- a. *Annual Tests:* During each federal fiscal year (October 1 - September 30), the permittee shall have a formal compliance test conducted for CO, NO<sub>x</sub> and visible emissions.
- b. *Tests Prior to Renewal:* Prior to renewing the air operation permit, the permittee shall conduct compliance tests for CO, NO<sub>x</sub>, VOC, and visible emissions from the combustion turbine. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants that are required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. Compliance testing is only required during the combustion of natural gas fuel.
- c. *Tests After Substantial Modifications:* All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shakedown period of air pollution control equipment. Shakedown periods shall not exceed 100 days after re-starting the combustion turbine.
- d. If the unit does not combust natural gas for greater than 400 hours during the federal fiscal year, the annual compliance tests are not required, and the annual CO RATA test shall be conducted in conjunction with the next required Part 75 NO<sub>x</sub> RATA. Annual RATA testing at 100% output may be utilized to satisfy the annual testing requirements for CO and NO<sub>x</sub>. No other methods may be used for compliance testing without prior written approval from the Department.

[1050221-004-AC; 40 CFR 60.7 and 60.8; Rules 62-297.310(7)(a)4 and 9, F.A.C.]

**B.15 Fuel Sulfur Monitoring.** The permittee shall demonstrate compliance with the fuel sulfur limit for natural gas specified in this permit by maintaining records of the average sulfur content of the natural gas being supplied for each month of operation in accordance with the following methods: ASTM D1072-80/90/94; D3031-81/86; D3246-81/92; D4084-82/94; D4468-85; D5504-94; the latest editions or in accordance with approved 40 CFR Part 75 methods. The owner or operator shall determine compliance with the sulfur content standard of 0.05% by weight for distillate oil in accordance with the following methods: ASTM D129-91; D1552-90; D2280-71; D2880-96; D2622-92; D4292; D4294-90; the latest editions or in accordance with approved 40 CFR Part 75 methods. These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule or natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335. However, the permittee is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used to determine the fuel sulfur content for compliance with the 40 CFR 60.333 SO<sub>2</sub> standard. [Rules 62-4.070(3) and 62-4.160(15); and 1050221-004-AC]

#### RECORD KEEPING AND REPORTING REQUIREMENTS

**B.16 Records of CO and NO<sub>x</sub> Caps.** Annual (12-month rolling total) NO<sub>x</sub> and CO limits shall be recalculated monthly and available on site for inspection purposes. Additionally, each year the facility shall submit all 12 months worth of calculations as part of the AOR submission. [1050221-004-AC]

**B.17 Monthly Operations Summary.** By the fifth calendar day of each month, the permittee shall record the

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### SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

#### Subsection B. Simple Cycle Combustion Turbine

hours of operation by fuel type, 12-month emission totals for NO<sub>x</sub> and CO and amount of each fuel fired for the combustion turbine. Likewise, by the fifth calendar day of each month, the 12-month emission totals for the NO<sub>x</sub> requirements that have been placed upon the existing EU-001 by this permit shall be recorded. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C. and 1050221-004-AC]

**B.18 Common Conditions.** See Appendix C of this permit for additional generic record keeping, reporting and notification requirements. [Chapters 62-4, 62-210, 62-296 and 62-297]

#### OTHER REQUIREMENTS

**B.19 NSPS Provisions.** The combustion turbine is subject to applicable requirements in Subpart A (General Provisions) and Subpart GG (Stationary Gas Turbines) of 40 CFR 60. See Appendices D and F of this permit.

### SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

#### Subsection C. Combustion Turbine-Electrical Generators

This section addresses the following emissions units.

| EU No.               | Brief Description                                                                                                               |
|----------------------|---------------------------------------------------------------------------------------------------------------------------------|
| Osprey Energy Center |                                                                                                                                 |
| 007                  | Nominal 170 MW combustion turbine-electrical generator set consisting of a Siemens Westinghouse "F" Class Model No. 501FD unit. |
| 008                  | Nominal 170 MW combustion turbine-electrical generator set consisting of a Siemens Westinghouse "F" Class Model No. 501FD unit. |
| 009                  | HRSB equipped with 250 MMBtu per hour gas-fired duct burner system.                                                             |
| 010                  | HRSB equipped with 250 MMBtu per hour gas-fired duct burner system.                                                             |

Emissions Units 007 – 011 comprise a nominal 540 MW combined cycle unit consisting of two combustion turbines, two HRSB with duct burner systems, and one shared nominal 200 MW steam-electrical generator set. Each CT is fired solely with pipeline natural gas and equipped with inlet foggers on the inlet air system. Each system employs selective catalytic reduction (SCR) to control NO<sub>x</sub> emissions. Continuous emissions monitoring systems are used to determine compliance with NO<sub>x</sub> emission standards. The HRSB duct burners use low NO<sub>x</sub> burners to fire natural gas for peak power production.

Although SCR systems are installed on the combined cycle units, CAM does not apply because compliance with the NO<sub>x</sub> emission standards is demonstrated by CEMS.

*{Permitting Note: Emissions units 007 and 008 are regulated under Phase II of the federal Acid Rain Program; NSPS Subpart A (General Provisions) and NSPS Subpart GG (Stationary Gas Turbines) in 40 CFR 60; and Rule 212.400(PSD), F.A.C. Emissions units 009 and 010 are regulated under NSPS Subpart A (General Provisions), NSPS Subpart Da (Standards for Performance for Electric Utility Steam Generating Units for Units Constructed After September 18, 1978) in 40 CFR 60; and Rule 212.400(PSD), F.A.C.}*

#### ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

**C.1 Authorized Fuels.** Only natural gas shall be fired in each combustion turbine and each HRSB duct burner system. Fuel oil firing is not permitted. [Rule 62-210.200(PTE), F.A.C. and PSD-FL-287]

**C.2 Permitted Capacity - Combustion Turbines:** Based on the lower heating value (LHV) of the fuel at ISO conditions, the maximum heat input rate shall not exceed 1,875 MMBtu/hour when firing natural gas without power augmentation. The maximum heat input rate will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be maintained by the plant. [Rule 62-210.200(PTE), F.A.C. and PSD-FL-287A]

**C.3 Permitted Capacity - HRSB with Duct Burners.** The maximum heat input rate from firing natural gas of each HRSB duct burner system shall not exceed 250 MMBtu/hour based on the (LHV). [Rule 62-210.200(PTE), F.A.C.]

**C.4 Hours of Operation.** The maximum allowable hours of operation for the 527 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. [Rule 62-210.200(PTE), F.A.C. and PSD-FL-287]

**C.5 SCR System.** The permittee shall operate and maintain the SCR system at all times of combustion turbine operation except during periods of startup and shutdown as dictated by manufacturer's guidelines and in accordance with this permit. [Rule 62-210.650, F.A.C. and PSD-FL-287]

#### EMISSION LIMITATIONS AND STANDARDS

**C.6 NO<sub>x</sub> Standards.**

- a. Combustion Turbine On and Duct Burner On or Off: As determined by CEMS, the concentration of NO<sub>x</sub> in the stack exhaust gas shall not exceed 3.5 ppmvd corrected to 15% oxygen based on a 24-hour block

### SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

#### Subsection C. Combustion Turbine-Electrical Generators

average. This limit shall also apply whether or not each unit is operating with duct burner on and/or in power augmentation mode.

**b. Combustion Turbine On with Power Augmentation and Duct Burners On:** As demonstrated by annual stack test, NO<sub>x</sub> emissions shall not exceed 27.5 lb/hour (at 95° F ambient temperature).

**c. Duct Burner System (Only):** NO<sub>x</sub> emissions from the duct burner systems shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS Subpart Da standards (see Appendix E of this permit). When NO<sub>x</sub> monitoring data is not available, substitution for missing data shall be handled as required by 40 CFR 75 to calculate any specified average time. As allowed for in Condition C.12 CEMS data collected during the following periods may be excluded from the 24-hour block average: limited startup data; limited shutdown data; and missing data as defined by 40 CFR 75.

[Rules 62-4.070 and 62-212.400(PSD), F.A.C.; PSD-FL-287; 40 CFR 60.334(b)(3)(iii)]

**C.7 Ammonia Slip Standard.** As determined by the ammonia testing and monitoring provisions of the subsection, the concentration of ammonia in the exhaust gas shall not exceed 9.0 ppmvd corrected to 15% oxygen. [Rules 62-4.070 and 62-212.400(PSD), F.A.C.; and PSD-FL-287]

**C.8 CO Standards.** As demonstrated by CEMS, CO emissions shall not exceed the following.

**d. For those days when no valid hour includes the use of duct burner firing, power augmentation or operation below 30% base load (excluding periods of startup and shutdown):** CO emissions in the stack exhaust gas shall not exceed 10 ppmvd corrected to 15% oxygen (at ISO conditions) based on a 24-hour block average.

**e. For those days when at least one valid hour includes the use of duct burner firing, power augmentation or operation below 30% base load (excluding periods of startup and shutdown):** CO emissions in the stack exhaust gas shall not exceed 17 ppmvd corrected to 15% oxygen (at ISO conditions) based on a 24-hour block average.

[Rule 62-212.400, F.A.C. and PSD-FL-287]

**C.9 VOC Standards.** As demonstrated by initial tests, VOC emissions shall not exceed the following.

**f. Base load with the Duct Burner Off:** VOC emissions in the stack exhaust gas shall not exceed 2.3 ppmvd corrected to 15% oxygen (at ISO conditions) and 5.8 lb/hour.

**g. Base load with Power Augmentation and the Duct Burner On:** VOC emissions in the stack exhaust gas shall not exceed 4.6 ppmvd corrected to 15% oxygen (at ISO conditions) and 12.4 lb/hour.

[Rule 62-212.400, F.A.C. and PSD-FL-287]

**C.10 SO<sub>2</sub> Standards:** SO<sub>2</sub> emissions shall be limited by firing natural gas with a maximum sulfur content of 2 grains/100 standard cubic feet of gas. Compliance with this requirement shall be demonstrated by implementing the fuel monitoring provisions specified in this subsection as well as the applicable requirements in NSPS Subparts Da (Duct Burners) and GG (Combustion Turbines) in 40 CFR 60 regarding the SO<sub>2</sub> emissions standards. {Permitting Note: This effectively limits the combined SO<sub>2</sub> emissions from EU-007 and EU-008 to 95.4 tons/year.} [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.; PSD-FL-287; and Subparts Da and GG in 40 CFR 60]

**C.11 PM/PM<sub>10</sub> and VE Standards:** Visible emissions shall not exceed 10% opacity. As demonstrated by initial stack tests, PM/PM<sub>10</sub> emissions from each unit shall not exceed 24.1 lb/hour at 100% output with the duct burner on and operating in the power augmentation mode. [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.; and PSD-FL-287]

#### EXCESS EMISSIONS

**C.12 Excess Emissions.** Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized.

## SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

### Subsection C. Combustion Turbine-Electrical Generators

Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to, and shutdowns from, combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. Operation below 30% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [Rule 62-210.700(3), F.A.C. and PSD-FL-287]

**C.13 Reporting Excess Emission.** If a unit exceeds the CO or NO<sub>x</sub> emissions standards based on 24-hour block average, the permittee shall report the excess emissions to the Compliance Authority within one working day. Also, for the purpose of reporting excess NO<sub>x</sub> emissions in accordance with 40 CFR 60.334, the NO<sub>x</sub> CEMS shall be used in lieu of the water-to-fuel ratio data. [Rules 62-210.700, 62-4.130 and 62-4.160(8), F.A.C.; 40 CFR 60.7; and PSD-FL-287].

### MONITORING OF OPERATIONS

**C.14 CO and NO<sub>x</sub> CEMS.** To demonstrate continuous compliance with the applicable standards, the permittee shall install, calibrate, maintain, and operate CEMS in each stack to measure and record CO and NO<sub>x</sub> emissions and oxygen concentration from these units.

**h. NO<sub>x</sub> CEMS:** The NO<sub>x</sub> monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. Annual RATA tests required for the NO<sub>x</sub> monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The span for the NO<sub>x</sub> monitor shall be based on the emissions standards. The use of the missing data substitution methodology provided in Subpart D of 40 CFR 75 is not required for identifying excess NO<sub>x</sub> emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in 40 CFR 60.7(c). As allowed for in Condition C.12 CEMS data collected during the following periods may be excluded from the 24-hour block average: limited startup data; limited shutdown data; and missing data as defined by 40 CFR 75. Upon request from DEP, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards listed within this permit and established in 40 CFR 60.332.

**i. CO and Oxygen CEMS:** The permittee shall install, operate and maintain a CO CEMS certified pursuant to Performance Specification 4 in Appendix B of 40 CFR 60. The oxygen monitor shall be certified pursuant to Performance Specification 3 in Appendix B of 40 CFR 60. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The span for the CO monitor shall be based on the emissions standards. The RATA tests required for the oxygen monitor shall be performed using EPA Method 3B in Appendix A of 40 CFR 60. The span for the oxygen monitor shall not be greater than 21%.

**j. Continuous Compliance:** Continuous compliance with the applicable CO and NO<sub>x</sub> emission limits shall be demonstrated by CEMS. Based on the CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Valid hourly emission rates shall not include periods of start up or shutdown unless prohibited by 62-210.700 F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two measurements are obtained at least 15 minutes apart. Excess emissions periods shall be reported as required in Conditions C.12 and C.13. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and PSD-FL-287.]



## SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

### Subsection C. Combustion Turbine-Electrical Generators

k. **CEMS Data Exclusion – Combustor Tuning.** CEMS data collected during initial or other major combustor tuning sessions shall be excluded from the CEMS compliance demonstration for short term emission standards provided the tuning session is performed in accordance with the manufacturer's specifications. All valid emissions data shall be used to demonstrate compliance with annual emissions caps. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Department's Southwest District Compliance Authority with advance notice that details the activity and proposed tuning schedule. The notice shall be by telephone, facsimile transmittal, or electronic mail. [Rules 62-4.070(3), 62-212.400(PSD), F.A.C., 62-210.700(5) F.A.C. and PSD-FL-185A]

**C.15 Fuel Monitoring.** To demonstrate compliance with the fuel sulfur limit of this permit, the permittee shall use the appropriate sampling and analytical methods identified in either Appendix D of 40 CFR 75 or 40 CFR 60.335. The monitoring frequency shall be determined by the requirements of 40 CFR 60.334 or an approved custom fuel monitoring schedule in accordance with Appendix D of 40 CFR 75 or 40 CFR 60.334. [PSD-FL-287]

### COMPLIANCE TESTING

**C.16 Test Methods.** As required, the following test methods shall be used to determine emissions.

| Method | Description of Method and Comments                                                                                                                                                                                                                                            |
|--------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1-4    | Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content                                                                                                                                                                                                   |
| 5      | Determination of Particulate Emissions from Stationary Sources.                                                                                                                                                                                                               |
| 7E     | Determination of Nitrogen Oxide Emissions from Stationary Sources                                                                                                                                                                                                             |
| 9      | Visual Determination of the Opacity of Emissions from Stationary Sources                                                                                                                                                                                                      |
| 10     | Determination of Carbon Monoxide Emissions from Stationary Sources                                                                                                                                                                                                            |
| 18     | Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) <i>{Note: Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions, if specifically requested.}</i>                 |
| 19     | Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates <i>{Note: Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.}</i> |
| 20     | Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines                                                                                                                                                                           |
| 25     | Method for Determining Gaseous Organic Concentrations                                                                                                                                                                                                                         |
| 25A    | Method for Determining Gaseous Organic Concentrations (Flame Ionization)                                                                                                                                                                                                      |
| 26A    | (Modified) Method for Determining Ammonia Emissions                                                                                                                                                                                                                           |
| 206    | Method for Determining Ammonia Emissions (Ion Chromatographic Analysis)                                                                                                                                                                                                       |
| 320    | Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy (for Ammonia)                                                                                                                                         |

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A; 40 CFR 60.334; and PSD-FL-287]

**C.17 Frequency of Compliance Tests.** The permittee shall conduct the following compliance tests:

- a. **Initial Tests:** Initial tests were required for CO, NO<sub>x</sub>, PM, VOC, ammonia and visible emissions.
- b. **Annual Tests:** During each federal fiscal year (October 1 - September 30), the permittee shall have a formal compliance test conducted for CO, NO<sub>x</sub>, ammonia and visible emissions. The required annual RATA test data may be used to demonstrate compliance with the annual test requirement for CO and NO<sub>x</sub> emissions.

## SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

### Subsection C. Combustion Turbine-Electrical Generators

Compliance with the CO standards serves as a surrogate for compliance with the VOC standards.

**c. Tests Prior to Renewal:** Prior to renewing the air operation permit, the permittee shall conduct compliance tests for CO, NO<sub>x</sub>, PM, VOC, and visible emissions from the combustion turbine. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants that are required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision.

**d. Tests After Substantial Modifications:** All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shakedown period of air pollution control equipment. Shakedown periods shall not exceed 100 days after re-starting the combustion turbine.

**e. Ammonia Slip:** For each required test, the permittee shall calculate and report the ammonia slip (ppmvd @ 15% O<sub>2</sub>) at the measured NO<sub>x</sub> emission rate (lb/hour) as a means of compliance with the BACT standard.

[PSD-FL-287; 40 CFR 60.7 and 60.8; Rules 62-297.310(7)(a)4 and 9, F.A.C.]

**C.18 Testing procedures:** Unless otherwise specified, testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test with 100% represented by a curve depicting heat input vs. compressor inlet temperature. Procedures for these tests shall meet all applicable requirements in Appendix C of this permit. [PSD-FL-287]

**C.19 SCR and Ammonia Slip.** The permittee shall be capable of calculating ammonia slip at the Department's request according to the following procedure.

- a.** In accordance with the manufacturer's specifications, the permittee shall calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of each unit.
- b.** The permittee shall develop performance curves for the appropriate ammonia injection rate versus load based on data collected by the NO<sub>x</sub> CEMS and the ammonia flow meter. During periods of CEMS downtime, the permittee shall operate at an ammonia flow rate for the given operating load to ensure compliance with the NO<sub>x</sub> standard.
- c.** Similarly, the permittee shall conduct tests for a range of load conditions and shall determine and report the ammonia flow rate required to comply with the ammonia and NO<sub>x</sub> standards. During periods of NO<sub>x</sub> CEMS downtimes or malfunctions, the permittee shall adjust the ammonia injection rate based on the previous quarter's operating hours for NO<sub>x</sub>, ammonia flow and load and adjust the ammonia flow rate as necessary to comply with NO<sub>x</sub> standard.
- d.** Ammonia emissions shall be calculated continuously using inlet and outlet NO<sub>x</sub> concentrations from the SCR system and ammonia flow supplied to the SCR system. The calculation procedure shall be provided with the CEMS monitoring plan required by 40CFR Part 75. The following calculation represents one means by which the permittee may demonstrate compliance with this condition:

$$\text{Ammonia Slip (ppmvd @ 15\% O}_2\text{)} = (A - (BC/1,000,000)) (1,000,000/B) (D)$$

Where:

- A = ammonia injection rate (lb/hour) / 17 lb/lb-mol
- B = dry gas exhaust flow rate (lb/hour) / 29 lb/lb-mol
- C = change in measured NO<sub>x</sub> (ppmvd @ 15% O<sub>2</sub>) across catalyst
- D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip.

The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device

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### SECTION 3. EMISSION UNIT SPECIFIC CONDITIONS

#### Subsection C. Combustion Turbine-Electrical Generators

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utilized to make the ammonia emission measurement and submitted with each annual compliance test. The calculation will exclude periods of startup and shutdown when determining the ammonia slip limit. The permittee shall notify the Department within 2 business days if the calculated ammonia emissions exceed 9.0 ppmvd corrected to 15% O<sub>2</sub> over a 3-hour block average. The notification shall include a corrective action plan to reduce ammonia emissions below 9 ppmvd corrected to 15% O<sub>2</sub> over a 3-hour block average. Upon specific request by the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements to demonstrate compliance with all NO<sub>x</sub> and ammonia slip related permit limits. [PSD-FL-287]

**C.20** Common Conditions. See Appendix C of this permit for additional generic record keeping, reporting and notification requirements. [Chapters 62-4, 62-210, 62-296 and 62-297]

#### RECORDS AND REPORTS

**C.21** Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. [PSD-FL-287]

**C.22** Common Conditions. See Appendix C of this permit for additional generic record keeping, reporting and notification requirements. [Chapters 62-4, 62-210, 62-296 and 62-297]

#### OTHER REQUIREMENTS

**C.23** NSPS Provisions. The combustion turbines are subject to the applicable requirements of Subpart A (General Provisions) and Subpart GG (Stationary Gas Turbine) in 40 CFR 60. See Appendices D and F of this permit. The HRSG equipped with duct burner systems are subject to the applicable requirements of Subpart A (General Provisions) and Subpart Da (Standards for Performance for Electric Utility Steam Generating Units for Units Constructed After September 18, 1978) in 40 CFR 60. See Appendices D and E of this permit.

## SECTION 4. ACID RAIN PART

**Subsection A.** This section addresses the following acid rain units.

**Operated by:** Auburndale Operating Services Company, Inc.

**ORIS Code:** 54658, Auburndale Power Plant and Auburndale Peak Energy Center  
55412, Osprey Energy Center

| EU No.                        | Brief Description                                                                                                                                                                             |
|-------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Auburndale Power Plant        |                                                                                                                                                                                               |
| 001                           | Nominal 156 MW combined cycle unit consisting of a combustion turbine-electrical generator set rated at 121.5 MW, an unfired HRSG and a nominal 52 MW steam turbine-electrical generator set. |
| Auburndale Peak Energy Center |                                                                                                                                                                                               |
| 006                           | Nominal 120 MW simple cycle combustion turbine-electrical generator set                                                                                                                       |
| Osprey Energy Center          |                                                                                                                                                                                               |
| 007                           | Nominal 170 MW combined cycle combustion turbine-electrical generator set                                                                                                                     |
| 008                           | Nominal 170 MW combined cycle combustion turbine-electrical generator set                                                                                                                     |

**A.1 Acid Rain Part.** The Phase II Acid Rain Part application is a part of this permit. The owners and operators of the Phase II acid rain units must comply with the standard requirements and special provisions set forth in the following application: DEP Form No. 62-210.900(1)(a), effective 04/16/01, received August 15, 2002 and August 29, 2001. [Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

**A.2 SO<sub>2</sub> allowances.** The SO<sub>2</sub> allowance allocations for each Acid Rain unit are as follows:

| EU No. | EPA ID | SO <sub>2</sub> Allowances to be Determined by EPA |      |      |      |      |
|--------|--------|----------------------------------------------------|------|------|------|------|
|        |        | 2003                                               | 2004 | 2005 | 2006 | 2007 |
| 001    | 1      | 0*                                                 | 0*   | 0*   | 0*   | 0*   |
| 006    | 6      | 0*                                                 | 0*   | 0*   | 0*   | 0*   |
| 007    | CT-1   | 0*                                                 | 0*   | 0*   | 0*   | 0*   |
| 008    | CT-2   | 0*                                                 | 0*   | 0*   | 0*   | 0*   |

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

**A.3 Emission Allowances.** Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

- 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.
- No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
- Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c), F.A.C.]

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

**A.5 Comments, Notes and Justifications:** The designated representative was changed by letter dated July 5, 2007, with a revised Certificate of Authorization.

## SECTION 4. ACID RAIN PART

Acid Rain Part- Page 1

# 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 **Auburndale Cogeneration Facility**

State **Florida**

ORIS Code **54658**

### 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<br>Unit ID# | b<br>Unit will hold allowances in accordance with 40 CFR 72.9(c)(1) | c<br>New Units<br><br>Commence Operation Date | d<br>New Units<br><br>Monitor Certification Deadline |
|---------------|---------------------------------------------------------------------|-----------------------------------------------|------------------------------------------------------|
| 1             | Yes                                                                 |                                               |                                                      |
| 6             | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |
|               | Yes                                                                 |                                               |                                                      |

## SECTION 4. ACID RAIN PART

Acid Rain Part - Page 2

Plant Name (from Step 1) Auburndale Cogeneration  
Facility

### 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 effect 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,

## SECTION 4. ACID RAIN PART

Acid Rain Part - Page 3

STEP 3.  
Cont'd.

Plant Name (from Step 1) Auburndale Cogeneration  
Facility

### 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 1 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 78.11 (NO<sub>x</sub> 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 72.7 or 72.8 shall be construed as:

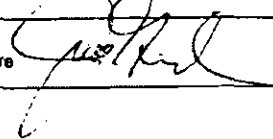
- (1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of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

STEP 4

### Certification

Read the  
certification  
statement, sign,  
and date

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 Jason Goodwin                                                                            |             |
| Signature  | Date 7/2/07 |

## SECTION 4. ACID RAIN PART

Acid Rain Part- Page 1

# 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 Osprey Energy Center | State Florida | ORIS Code 55412 |
|---------------------------------|---------------|-----------------|

### 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        | b                                                              | c                                        | d                                               |
|----------|----------------------------------------------------------------|------------------------------------------|-------------------------------------------------|
| Unit ID# | Unit will hold allowances in accordance with 40 CFR 72.9(c)(1) | New Units<br><br>Commence Operation Date | New Units<br><br>Monitor Certification Deadline |
| CT1      | Yes                                                            |                                          |                                                 |
| CT2      | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |
|          | Yes                                                            |                                          |                                                 |



## SECTION 4. ACID RAIN PART

Acid Rain Part - Page 2

Plant Name (from Step 1) Osprey Energy Center

### 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

## SECTION 4. ACID RAIN PART

Acid Rain Part - Page 3

Plant Name (from Step 1) Osprey Energy Center

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<sub>x</sub> 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 72.7 or 72.8 shall be construed as:

- (1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
- (2) Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
- (3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudency 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.

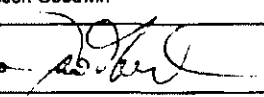
STEP 4

### Certification

Read the  
certification  
statement, sign,  
and date

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 Jason Goodwin

Signature 

Date 7/2/07

## **SECTION 5. APPENDICES**

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## SECTION 5. APPENDIX A

### Citation Formats

*The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.*

#### REFERENCES TO PREVIOUS PERMITTING ACTIONS

##### Old Permit Numbers

*Example:* Permit No. AC50-123456 or Air Permit No. AO50-123456

*Where:* “AC” identifies the permit as an Air Construction Permit  
“AO” identifies the permit as an Air Operation Permit  
“123456” identifies the specific permit project number

##### New Permit Numbers

*Example:* Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

*Where:* “099” represents the specific county ID number in which the project is located  
“2222” represents the specific facility ID number  
“001” identifies the specific permit project  
“AC” identifies the permit as an air construction permit  
“AF” identifies the permit as a minor federally enforceable state operation permit  
“AO” identifies the permit as a minor source air operation permit  
“AV” identifies the permit as a Title V Major Source Air Operation Permit

##### PSD Permit Numbers

*Example:* Permit No. PSD-FL-317

*Where:* “PSD” means issued pursuant to the Prevention of Significant Deterioration of Air Quality  
“FL” means that the permit was issued by the State of Florida  
“317” identifies the specific permit project

#### RULE CITATION FORMATS

##### Florida Administrative Code (F.A.C.)

*Example:* [Rule 62-213.205, F.A.C.]

*Means:* Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

##### Code of Federal Regulations (CFR)

*Example:* [40 CFR 60.7]

*Means:* Title 40, Part 60, Section 7

## SECTION 5. APPENDIX B

### General Conditions

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
  - a. Have access to and copy and records that must be kept under the conditions of the permit;
  - b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
  - c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
  - a. A description of and cause of non-compliance; and
  - b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

## SECTION 5. APPENDIX B

### General Conditions

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
  - a. Determination of Best Available Control Technology;
  - b. Determination of Prevention of Significant Deterioration; and
  - c. Compliance with New Source Performance Standards.
14. The permittee shall comply with the following:
  - a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
  - b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
  - c. Records of monitoring information shall include:
    - 1) The date, exact place, and time of sampling or measurements;
    - 2) The person responsible for performing the sampling or measurements;
    - 3) The dates analyses were performed;
    - 4) The person responsible for performing the analyses;
    - 5) The analytical techniques or methods used; and
    - 6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

## SECTION 5. APPENDIX C

### Common Conditions

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.

#### EMISSIONS AND CONTROLS

1. Plant Operation – Problems. If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention. The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. This rule cannot vary any requirement of a federal NSPS or NESHAP provision. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited. Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions – Notification. In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program 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.]
6. VOC or OS Emissions. No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. No VOC/OS controls have been ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited. No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200, F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

#### COMPLIANCE TESTING REQUIREMENTS

9. 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 two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]
10. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

## SECTION 5. APPENDIX C

### Common Conditions

Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

11. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
12. Applicable Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.
  - 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 or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
  - c. Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sample 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, F.A.C. below.

| 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                     | Calibration liquid 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 |



## SECTION 5. APPENDIX C

### Common Conditions

| ITEM                            | MINIMUM CALIBRATION FREQUENCY                                                                                                              | REFERENCE INSTRUMENT                                                            | TOLERANCE                                                                    |
|---------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------|------------------------------------------------------------------------------|
| Probe Nozzles                   | Before each test or when nicked, dented, or corroded                                                                                       | Micrometer                                                                      | +/-0.001" mean of at least 3 readings max. deviation between readings 0.004" |
| Dry Gas Meter and Orifice Meter | 1. Full Scale: Annually<br>- When received;<br>- When 5% change observed.<br>2. One Point: Semiannually<br>3. Check after each test series | Spirometer or calibrated wet test or dry gas test meter<br><br>Comparison check | 2%<br><br>5%                                                                 |

- 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.]

13. Determination of Process Variables [Rule 62-297.310(5), F.A.C.]

- 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.

14. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E. [Rule 62-297.310(6), F.A.C.]

- a. *Permanent Test Facilities.* The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.
- b. *Temporary Test Facilities.* The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.
- c. *Sampling Ports.*
  - (1) All sampling ports shall have a minimum inside diameter of 3 inches.
  - (2) The ports shall be capable of being sealed when not in use.
  - (3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.
  - (4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.
  - (5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance

## SECTION 5. APPENDIX C

### Common Conditions

with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms.*

- (1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.
- (2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.
- (3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.
- (4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

- (1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.
- (2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power.*

- (1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.
- (2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

- (1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.
  - (a) The bracket shall be a standard 3 inch x 3 inch x one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.
  - (b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.
  - (c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.
- (2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.
- (3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

15. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required. [Rule 62-297.310(7), F.A.C.]

a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.
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.

## SECTION 5. APPENDIX C

### Common Conditions

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 sub-subparagraph 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) 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.
  6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.
  7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.
  8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
  9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
  10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.
- 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 shall 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 paragraph 62-297.310(7)(b), F.A.C., shall apply.

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### Common Conditions

#### RECORDS AND REPORTS

16. Test Reports: [Rule 62-297.310(8), F.A.C.]

- 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.

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**NSPS Subpart A, General Provisions**

**Subpart A - General Provisions for 40 CFR 60**

[Source: Federal Register dated 7/1/98, Federal Register 5/8/98, 2/12/99, 10/17/00, 6/28/02, 6/1/06]

In accordance with Rule 62-204.800(8), F.A.C., the following emissions units are subject to the applicable requirements of 40 CFR 60 Subpart A, General Provisions. For these requirements, the original federal rule numbering has been retained.

| EU No.                        | Brief Description                                                                                                                                                                                                  |
|-------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Auburndale Power Plant        |                                                                                                                                                                                                                    |
| 001                           | Nominal 156 MW combined cycle unit consisting of a nominal 121 MW combustion turbine-electrical generator set, an unfired heat recovery steam generator (HRSG) and a nominal 35 MW steam-electrical generator set. |
| Auburndale Peak Energy Center |                                                                                                                                                                                                                    |
| 006                           | Nominal 120 MW combustion turbine-electrical generator set; simple cycle operation                                                                                                                                 |
| Osprey Energy Center          |                                                                                                                                                                                                                    |
| 007                           | Nominal 170 MW combustion turbine-electrical generator set; part of a combined cycle unit*                                                                                                                         |
| 008                           | Nominal 170 MW combustion turbine-electrical generator set; part of a combined cycle unit*                                                                                                                         |
| 009                           | HRSG equipped with 250 MMBtu per hour duct burner system; part of a combined cycle unit*                                                                                                                           |
| 010                           | HRSG equipped with 250 MMBtu per hour duct burner system; part of a combined cycle unit*                                                                                                                           |

\* Emissions Units 007 – 010 comprise a nominal 540 MW combined cycle units consisting of two combustion turbines, two HRSG with duct burner systems, and one shared nominal 200 MW steam-electrical generator set.

**40 CFR 60.1 Applicability.**

(a) Except as provided in 40 CFR 60 subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (CAA) as amended November 15, 1990 (42 U.S.C. 7661).

**40 CFR 60.5 Determination of construction or modification.**

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

**40 CFR 60.6 Review of plans.**

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b) (1) A separate request shall be submitted for each construction or modification project.

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(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

**40 CFR 60.7 Notification and record keeping.**

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) Reserved.

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in § 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5) of 40 CFR 60. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

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(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in Figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

*{See Figure 1, Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance, at the end of this section.}*

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

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

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

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

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

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system

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performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in 40 CFR 60.7(a) is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of 40 CFR 60.7(a).

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

**40 CFR 60.8 Performance tests.**

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7



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days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes

(i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and

(ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

**§ 60.9 Availability of information.**

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by §§ 2.201 through 2.213 of this chapter and not by § 2.301 of this chapter.)

**40 CFR 60.10 State authority.**

The provisions of 40 CFR 60 shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

**40 CFR 60.11 Compliance with standards and maintenance requirements.**

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which

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may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e) (1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR 60.8 unless one of the following conditions apply. If no performance test under 40 CFR 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under 40 CFR 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in 40 CFR 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under 40 CFR 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in 40 CFR 60.11(e)(5), the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of 40 CFR 60, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in 40 CFR 60.11(e)(3), the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with 40 CFR 60.11(b), shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under 40 CFR 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in 40 CFR 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of 40 CFR 60.7(e)(1) shall apply.

(4) The owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by 40 CFR 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and 40 CFR 60.8 performance test results.

(5) The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS

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data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by 40 CFR 60.8, the opacity observation results and observer certification required by 40 CFR 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by 40 CFR 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with 40 CFR 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, the shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of 40 CFR 60.11.

**40 CFR 60.12 Circumvention.**

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

**40 CFR 60.13 Monitoring requirements.**

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under 40 CFR 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he/she shall conduct a performance evaluation of the COMS as specified in Performance Specification I, appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 40 CFR 60.8 and as described in 40 CFR 60.11(e)(5), shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 40 CFR 60.8 is conducted.

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(2) Except as provided in 40 CFR 60.13(c)(1), the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d) (1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 shall be used.

(g) (1) When more than one continuous monitoring system is used to measure the emissions from only one affected facility (e.g. multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless installation of fewer systems is approved by the Administrator.

(2) When the effluents from two or more affected facilities subject to the same opacity standard are combined before being released to the atmosphere, the owner or operator may either install a continuous opacity monitoring system at a location monitoring the combined effluent or install an opacity combiner system comprised of opacity and flow monitoring systems on each stream, and shall report as per Sec. 60.7(c) on the combined effluent. When the affected facilities are not subject to the same opacity standard applicable, except for documented periods of shutdown of the affected facility, subject to the most stringent opacity standard shall apply

(3) When the effluents from two or more affected facilities subject to the same emissions standard, other than opacity, are combined before released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the continuous monitoring standard, separate continuous monitoring systems shall be installed on each effluent and the owner or operator shall report as required for each affected facility.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous system breakdowns, repairs,

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calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. For owners or operators complying with the requirements in Sec. 60.7(f)(1) or (2), data averages must include any data recorded during periods of monitor breakdown or malfunction. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O<sub>2</sub> or ng or pollutant per J of heat input). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

[Rule 62-296.800, F.A.C.; 40 CFR 60.13(h)].

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

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

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

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

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

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

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

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

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

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

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in section 8.4 of Performance Specification 2 and substitute the procedures in section 16.0 if the results of a performance test conducted according to the requirements in 40 CFR 60.8 of this subpart or other tests performed following the criteria in 40 CFR 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

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(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure that the CEMS data indicate the source emissions approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., 40 CFR 60.45(g)(2) and 40 CFR 60.45(g)(3), 40 CFR 60.73(e), and 40 CFR 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in section 8.4 of Performance Specification 2.

**40 CFR 60.14 Modification.**

(a) Except as provided under 40 CFR 60.14(e) and 40 CFR 60.14(f), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr (lbs./hour) of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in 40 CFR 60.14(b)(1). When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 appendix C of 40 CFR 60 shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be

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accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in 40 CFR 60.14(a), compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j) (1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration project*, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

**40 CFR 60.15 Reconstruction.**

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

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- (1) Name and address of the owner or operator.
  - (2) The location of the existing facility.
  - (3) A brief description of the existing facility and the components which are to be replaced.
  - (4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.
  - (5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.
  - (6) The estimated life of the existing facility after the replacements.
  - (7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.
- (e) The Administrator will determine, within 30 days of the receipt of the notice required by 40 CFR 60.15(d) and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.
- (f) The Administrator's determination under 40 CFR 60.15(e) shall be based on:
- (1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;
  - (2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;
  - (3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and
  - (4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.
- (g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

**§ 60.18 General control device requirements.**

(a) *Introduction.* This section contains requirements for control devices used to comply with applicable subparts of parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section.

(b) *Flares.* Paragraphs (c) through (f) apply to flares.

(c) (1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i)(A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity,  $V_{max}$ , as determined by the following equation:

$$V_{max} = (XH_2 - K_1) * K_2$$

Where:

$V_{max}$  = Maximum permitted velocity, m/sec.

$K_1$  = Constant, 6.0 volume-percent hydrogen.

$K_2$  = Constant, 3.9(m/sec)/volume-percent hydrogen.

$XH_2$  = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 60.17).



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(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4) (i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity,  $V_{max}$ , as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity,  $V_{max}$ , as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f) (1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

Eq. 1

where:

$H_T$ =Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = \text{Constant} \cdot 1.740 \times 10^{-7} \left( \frac{1}{\text{ppm}} \right) \left( \frac{\text{g mole}}{\text{scm}} \right) \left( \frac{\text{MJ}}{\text{kcal}} \right)$$

where the standard temperature for  $\left( \frac{\text{g mole}}{\text{scm}} \right)$  is 20 °C;

Eq. 2

$C_i$ =Concentration of sample component  $i$  in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in § 60.17); and

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$H_i$ =Net heat of combustion of sample component  $i$ , kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity,  $V_{max}$ , for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.  $\text{Log}_{10}(V_{max}) = (HT + 28.8) / 31.7$

$V_{max}$ =Maximum permitted velocity, M/sec

28.8=Constant

31.7=Constant

HT=The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity,  $V_{max}$ , for air-assisted flares shall be determined by the following equation.

$V_{max} = 8.706 + 0.7084 (HT)$

$V_{max}$ =Maximum permitted velocity, m/sec

8.706=Constant

0.7084=Constant

HT=The net heating value as determined in paragraph (f)(3).

**§ 60.19 General notification and reporting requirements.**

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the post-mark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic

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reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f) (1) (i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

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**Figure 1. Summary Report**  
**Gaseous and Opacity Excess Emission and Monitoring System Performance**

Company: \_\_\_\_\_

Address: \_\_\_\_\_

Process Unit(s) Description: \_\_\_\_\_

Emission Limitation: \_\_\_\_\_

Pollutant (Circle One):    SO<sub>2</sub>    NO<sub>x</sub>    TRS    H<sub>2</sub>S    CO    Opacity

Reporting Period Dates: From \_\_\_\_\_ to \_\_\_\_\_

Total source operating time in reporting period <sup>1</sup>: \_\_\_\_\_

Monitor Manufacturer: \_\_\_\_\_

Monitor Model No.: \_\_\_\_\_

Date of Latest CMS Certification or Audit: \_\_\_\_\_

| <b>Emission Data Summary <sup>1</sup></b>                                                                                                                                                                                                                                                                                                                                                                  | <b>CMS Performance Summary <sup>1</sup></b>                                                                                                                                                                                                                                                                                                                                                   |
|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1. Duration of excess emissions in reporting period due to:<br>a. Startup/shutdown .....<br>b. Control equipment problems .....<br>c. Process problems .....<br>d. Other known causes .....<br>e. Unknown causes .....<br>2. Total duration of excess emissions .....<br>3. $\frac{[\text{Total duration of excess emissions}] \times (100\%)}{[\text{Total source operating time}]}$ ..... % <sup>2</sup> | 1. CMS downtime in reporting period due to:<br>a. Monitor equipment malfunctions .....<br>b. Non-Monitor equipment malfunctions .....<br>c. Quality assurance calibration .....<br>d. Other known causes .....<br>e. Unknown causes .....<br>2. Total CMS Downtime .....<br>3. $\frac{[\text{Total CMS Downtime}] \times (100\%)}{[\text{Total source operating time}]}$ ..... % <sup>2</sup> |

<sup>1</sup> For opacity, record all times in minutes. For gases, record all times in hours.

<sup>2</sup> For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

*On a separate page, describe any changes since last quarter in CMS, process or controls.*

I certify that the information contained in this report is true, accurate, and complete.

Name: \_\_\_\_\_

Signature: \_\_\_\_\_

Title: \_\_\_\_\_

Date: \_\_\_\_\_

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**40 CFR 60: Subpart Da**

**Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978**

In accordance with Rule 62-204.800(8), F.A.C., the following emissions units are subject to the applicable requirements of 40 CFR 60 Subpart A, General Provisions. For these requirements, the original federal rule numbering has been retained.

| EU No.                        | Brief Description                                                                                                                                                                                                  |
|-------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Auburndale Power Plant        |                                                                                                                                                                                                                    |
| 001                           | Nominal 156 MW combined cycle unit consisting of a nominal 121 MW combustion turbine-electrical generator set, an unfired heat recovery steam generator (HRSG) and a nominal 35 MW steam-electrical generator set. |
| Auburndale Peak Energy Center |                                                                                                                                                                                                                    |
| 006                           | Nominal 120 MW combustion turbine-electrical generator set; simple cycle operation                                                                                                                                 |
| Osprey Energy Center          |                                                                                                                                                                                                                    |
| 007                           | Nominal 170 MW combustion turbine-electrical generator set; part of a combined cycle unit*                                                                                                                         |
| 008                           | Nominal 170 MW combustion turbine-electrical generator set; part of a combined cycle unit*                                                                                                                         |
| 009                           | HRSG equipped with 250 MMBtu per hour duct burner system; part of a combined cycle unit*                                                                                                                           |
| 010                           | HRSG equipped with 250 MMBtu per hour duct burner system; part of a combined cycle unit*                                                                                                                           |

\* Emissions Units 007 – 010 comprise a nominal 540 MW combined cycle units consisting of two combustion turbines, two HRSG with duct burner systems, and one shared nominal 200 MW steam-electrical generator set.

**Sec. 60.40Da Applicability and designation of affected facility.**

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

- (1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and
- (2) For which construction, modification, or reconstruction is commenced after September 18, 1978.

(b) Heat recovery steam generators that are associated with stationary combustion turbines burning fuels other than 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. Heat recovery steam generators and the associated stationary combustion turbine(s) burning fuels containing 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average are subject to this part and are not subject to subpart KKKK of this part. This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the combined cycle gas turbine burn fuels other than synthetic-coal gas, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

**§ 60.41Da Definitions.**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

*Anthracite* means coal that is classified as anthracite according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77 (incorporated by reference -- see §60.17).

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*Available purchase power* means the lesser of the following:

- (a) The sum of available system capacity in all neighboring companies.
- (b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.
- (c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

*Available system capacity* means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

*Bituminous coal* means coal that is classified as bituminous according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90,

91, 95, 98a, or 99 (Reapproved 2004)<sup>e1</sup> (incorporated by reference, see Sec. 60.17).

*Boiler operating day* for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

*Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, 98a, or 99 (Reapproved 2004) [egr]1 (incorporated by reference, see Sec. 60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

*Coal-fired electric utility steam generating unit* means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

*Coal refuse* means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

*Cogeneration*, also known as "combined heat and power," means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

*Combined cycle gas turbine* means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

*Dry flue gas desulfurization technology or dry FGD* means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

*Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

*Electric utility combined cycle gas turbine* means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

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*Electric utility company* means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

*Electric utility steam generating unit* means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. For the purpose of this subpart, net-electric output is the gross electric sales to the utility power distribution system minus purchased power on a 12-month rolling average. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

*Electrostatic precipitator or ESP* means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

*Emergency condition* means that period of time when:

(a) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(1) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(2) All available purchase power interconnected with the affected facility is being obtained, or

(b) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(c) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under (a) of this definition apply.

*Emission limitation* means any emissions limit or operating limit.

*Emission rate period* means any calendar month included in a 12-month rolling average period.

*Federally enforceable* means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or 40 CFR 51.18 and 40 CFR 51.24.

*Fossil fuel* means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

*Gaseous fuel* means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.

*Gross output* means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

*24-hour period* means the period of time between 12:01 a.m. and 12:00 midnight.

*Interconnected* means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

*Integrated gasification combined cycle electric utility steam generating unit or IGCC* means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

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*ISO conditions* means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

*Lignite* means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, or 98a (incorporated by reference -- see §60.17).

*Natural gas means:*

- (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or
- (2) Liquid petroleum gas, as defined by the American Society of Testing and Materials (ASTM) Standard Specification for Liquid Petroleum Gases D1835-87, 91, 97, or 03a (incorporated by reference, see Sec. 60.17).

*Neighboring company* means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

*Net system capacity* means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

*Noncontinental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Petroleum* means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate, residual oil, and petroleum coke.

*Potential combustion concentration* means the theoretical emissions (ng/J, lb/million Btu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

- (a) For particulate matter is:
  - (1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and
  - (2) 73 ng/J (0.17 lb/million Btu) heat input for liquid fuels.
- (b) For sulfur dioxide is determined under § 60.48Da(b).
- (c) For nitrogen oxides is:
  - (1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;
  - (2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and
  - (3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

*Potential electrical output capacity* is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

*Principal company* means the electric utility company or companies which own the affected facility.

*Resource recovery unit* means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

*Responsible official* means responsible official as defined in 40 CFR 70.2.

*Solid-derived fuel* means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, and gasified coal.



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*Spare flue gas desulfurization system module* means a separate system of sulfur dioxide emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

*Spinning reserve* means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

*Steam generating unit* means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

*Subbituminous coal* means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, or 98a (incorporated by reference -- see §60.17).

*System emergency reserves* means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

*System load* means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (e.g., emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

*Wet flue gas desulfurization technology or wet FGD* means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

**Sec. 60.42Da Standard for particulate matter.**

(a) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain particulate matter in excess of:

- (1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;
- (2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and
- (3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification is commenced after February 28, 2005, except for modified affected facilities meeting the requirements of paragraph (d) of this section, any gases that contain particulate matter in excess of either:

- (1) 18 ng/J (0.14 lb/MWh) gross energy output; or

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(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in Sec. 60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in Sec. 60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel.

**Sec. 60.43Da Standard for sulfur dioxide.**

(a) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is complete, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC-I) any gases which contain sulfur dioxide in excess of 520 ng/J (1.20 lb/million Btu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/million Btu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite,

(2) Is classified as a resource recovery unit, or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/million Btu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

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(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO<sub>2</sub> commercial demonstration permit issued by the Administrator in accordance with the provisions of Sec. 60.45Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

- (1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

$$E_s = (340x + 520y)/100 \text{ and}$$

$$\%P_s = 10$$

- (2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

$$E_s = (340x + 520y)/100 \text{ and}$$

$$\%P_s = (10x + 30y)/100$$

where:

$E_s$  is the prorated sulfur dioxide emission limit (ng/J heat input),

$\%P_s$  is the percentage of potential sulfur dioxide emission allowed.

$x$  is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)

$y$  is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

[44 FR 33613, June 11, 1979, as amended at 54 FR 6663, Feb. 14, 1989; 54 FR 21344, May 17, 1989]

(i) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except as provided for under paragraphs (j) or (k) of this section, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

- (1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

- (2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

- (3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

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(j) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that is located in a noncontinental area, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

**Sec. 60.44Da Standard for nitrogen oxides.**

(a) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b) and (d) of this section, any gases which contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of the following emission limits, based on a 30-day rolling average, except as provided under § 60.46Da(j)(1):

(1) NO<sub>x</sub> emission limits.

| Fuel type               | Emission limit for heat input |                  |
|-------------------------|-------------------------------|------------------|
|                         | ng/J                          | (lb/million Btu) |
| Gaseous fuels:          |                               |                  |
| Coal-derived fuels..... | 210                           | 0.50             |

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|                                                                                                                                                                                             |                  |                  |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------|------------------|
| All other fuels.....                                                                                                                                                                        | 86               | 0.20             |
| Liquid fuels:                                                                                                                                                                               |                  |                  |
| Coal-derived fuels.....                                                                                                                                                                     | 210              | 0.50             |
| Shale oil.....                                                                                                                                                                              | 210              | 0.50             |
| All other fuels.....                                                                                                                                                                        | 130              | 0.30             |
| Solid fuels:                                                                                                                                                                                |                  |                  |
| Coal-derived fuels.....                                                                                                                                                                     | 210              | 0.50             |
| Any fuel containing more than 25%, by weight,<br>coal refuse.....                                                                                                                           | ( <sup>1</sup> ) | ( <sup>1</sup> ) |
| Any fuel containing more than 25%, by weight,<br>lignite if the lignite is mined in North<br>Dakota, South Dakota, or Montana, and is<br>combusted in a slag tap furnace <sup>2</sup> ..... | 340              | 0.80             |
| Any fuel containing more than 25%, by weight,<br>lignite not subject to the 340 ng/J heat<br>input emission limit <sup>2</sup> .....                                                        |                  |                  |
| Subbituminous coal.....                                                                                                                                                                     | 210              | 0.50             |
| Bituminous coal.....                                                                                                                                                                        | 260              | 0.60             |
| Anthracite coal.....                                                                                                                                                                        | 260              | 0.60             |
| All other fuels.....                                                                                                                                                                        | 260              | 0.60             |

<sup>1</sup> Exempt from NO<sub>x</sub> standards and NO<sub>x</sub> monitoring requirements.

<sup>2</sup> Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) NO<sub>x</sub> reduction requirement.

| Fuel type          | Percent reduction of potential combustion concentration |
|--------------------|---------------------------------------------------------|
| Gaseous fuels..... | 25                                                      |
| Liquid fuels.....  | 30                                                      |
| Solid fuels.....   | 65                                                      |

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of Sec. 60.45Da.

(c) Except as provided under paragraph (d) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$E_n = [86 w + 130 x + 210 y + 260 z + 340 v] / 100$$

where:

$E_n$  is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);  
 $w$  is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;  
 $x$  is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;  
 $y$  is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;  
 $z$  is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard;  
and

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y is the percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989]

(d) (1) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no new source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average, except as provided under Sec. 60.48Da(k).

(2) On and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no existing source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average.

(e) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an IGCC meeting the requirements of paragraph (f) of this section, any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under Sec. 60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, the owner or operator of an IGCC subject to the provisions of this subpart that burns liquid fuel as a supplemental fuel and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided for in paragraphs (f)(2) and (3) of this section.

(2) When burning liquid fuel exclusively or in combination with synthetic gas derived from coal such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

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**Sec. 60.45Da Standard for mercury.**

(a) For each coal-fired electric utility steam generating unit other than an integrated gasification combined cycle (IGCC) electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases which contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average using the procedures in Sec. 60.50Da(h).

- (1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of  $20 \times 10^{-6}$  pound per megawatt hour (lb/MWh) or 0.020 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0025 nanograms per joule (ng/J).
- (2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:
  - (i) If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of  $66 \times 10^{-6}$  lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.
  - (ii) If your unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of  $97 \times 10^{-6}$  lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.
- (3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of  $175 \times 10^{-6}$  lb/MWh or 0.175 lb/GWh on an output basis. The SI equivalent is 0.0221 ng/J.
- (4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of  $16 \times 10^{-6}$  lb/MWh or 0.016 lb/GWh on an output basis. The SI equivalent is 0.0020 ng/J.
- (5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (i.e., bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the monthly unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.
  - (i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the proportion of energy output (in British thermal units, Btu) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total Btu or megawatt hours contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^n EL_i (HH_i)}{\sum_{i=1}^n HH_i} \quad (\text{Eq. 1})$$

Where:

$EL_b$  = Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged under the blending provision.

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$EL_i$  = Hg emissions limit for the subcategory  $i$  (coal rank) that applies to affected source, lb/MWh.

$HH_i$  = Electricity output from affected source during the production period related to use of the corresponding subcategory  $i$  (coal rank) that falls within the compliance period, gross MWh generated by the electric utility steam generating unit.

$n$  = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from the unit that contain Hg in excess of the computed weighted Hg emission limit based on the proportion of electricity output (in MWh) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total megawatt hours contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases which contain Hg emissions in excess of  $20 \times 10^{-6}$  lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average using the procedures in Sec. 60.50Da(g).

#### Sec. 60.46Da [Reserved]

#### Sec. 60.47Da Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC-I) and who is issued a commercial demonstration permit by the Administrator is not subject to the  $SO_2$  emission reduction requirements under Sec. 60.43Da(c) but must, as a minimum, reduce  $SO_2$  emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the  $SO_2$  emission reduction requirements under Sec. 60.43Da(a) but must, as a minimum, reduce  $SO_2$  emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable  $NO_x$  emission limitation and percent reduction under Sec. 60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/million Btu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.



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| Technology                                  | Equivalent Pollutant | electrical capacity (MW electrical output) |
|---------------------------------------------|----------------------|--------------------------------------------|
| Solid solvent refined coal (SRC I).....     | SO <sub>2</sub>      | 6,000-10,000                               |
| Fluidized bed combustion (atmospheric)....  | SO <sub>2</sub>      | 400-3,000                                  |
| Fluidized bed combustion (pressurized)..... | SO <sub>2</sub>      | 400-1,200                                  |
| Coal liquification.....                     | NO <sub>x</sub>      | 750-10,000                                 |
| Total allowable for all technologies.....   |                      | 15,000                                     |

**Sec. 60.48Da Compliance provisions.**

(a) Compliance with the particulate matter emission limitation under Sec. 60.42Da(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under Sec. 60.42Da(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under Sec. 60.44Da(a) constitutes compliance with the percent reduction requirements under Sec. 60.44Da(a)(2).

(c) The particulate matter emission standards under Sec. 60.42Da, the nitrogen oxides emission standards under Sec. 60.44Da, and the Hg emission standards under Sec. 60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

- (1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,
- (2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and
- (3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical

output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (h) under Sec. 60.43Da for any period of operation lasting from 24 hours to 30 days when:

- (i) Any one flue gas desulfurization module is not operated,
- (ii) The affected facility is operating at the maximum heat input rate,
- (iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and
- (iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under Sec. 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under Sec. 60.43Da and the nitrogen oxides emission limitations under Sec. 60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under Sec. 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under Sec. 60.43Da and the nitrogen oxides emission limitation under Sec. 60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30

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successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

- (1) Compliance with applicable 30-day rolling average SO<sub>2</sub> and NO<sub>x</sub> emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO<sub>2</sub> and NO<sub>x</sub> for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO<sub>x</sub> only), or emergency conditions (SO<sub>2</sub> only).
- (2) Compliance with applicable SO<sub>2</sub> percentage reduction requirements is determined based on the average inlet and outlet SO<sub>2</sub> emission rates for the 30 successive boiler operating days.
- (3) Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under Sec. 60.49Da of this subpart, compliance of the affected facility with the emission requirements under Secs. 60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989]

(i) Compliance provisions for sources subject to Sec. 60.44Da(d)(1), (e)(1), or (f). The owner or operator of an affected facility subject to Sec. 60.44Da(d)(1) or (e)(1) shall calculate NO<sub>x</sub> emissions by multiplying the average hourly NO<sub>x</sub> output concentration, measured according to the provisions of Sec. 60.49Da(c), by the average hourly flow rate, measured according to the provisions of Sec. 60.49Da(l), and dividing by the average hourly gross energy output, measured according to the provisions of Sec. 60.49Da(k).

(j) Compliance provisions for duct burners subject to § 60.44Da(a)(1). To determine compliance with the emissions limits for NO<sub>x</sub> required by § 60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under § 60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under § 60.44Da (a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the continuous emission monitoring system specified under Sec. 60.49Da for measuring NO<sub>x</sub> and oxygen and meet the requirements of Sec. 60.49Da. Data from a CEMS certified (or recertified) according to the provisions of 40 CFR 75.20, meeting the QA and QC requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used. This includes data substituted according to 40 CFR 75.21(i) for invalid data and 40 CFR 75.30 for missing data or data adjusted for negative bias as required by 40 CFR 75.23(d). The sampling site shall be located at the outlet from the steam generating unit. The NO<sub>x</sub> emission rate at the outlet from the steam generating unit shall constitute the NO<sub>x</sub> emission rate from the duct burner of the combined cycle system.

(k) Compliance provisions for duct burners subject to Sec. 60.44Da(d)(1) or (e)(1). To determine compliance with the emission limitation for NO<sub>x</sub> required by Sec. 60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NO<sub>x</sub> emission limitation in Sec. 60.44Da(d)(1) or (e)(1) as follows:

- (i) The emission rate (E) of NO<sub>x</sub> shall be computed using Equation 1 of this section:

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$$E = [(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})] / (O_{sg} \times h) \text{ (Eq. 1)}$$

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

C<sub>sg</sub> = average hourly concentration of NOX exiting the steam generating unit, ng/dscm (lb/dscf)

C<sub>te</sub> = average hourly concentration of NOX in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)

Q<sub>sg</sub> = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Q<sub>te</sub> = average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)

O<sub>sg</sub> = average hourly gross energy output from steam generating unit, J (Mwh)

h = average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

(ii) Method 7E of appendix A of this part shall be used to determine the NOX concentrations (C<sub>sg</sub> and C<sub>te</sub>).

Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates (Q<sub>sg</sub> and Q<sub>te</sub>) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NOX emission limitation in Sec. 60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NOX emission limitation in Sec. 60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NOX shall be computed using Equation 2 of this section:

$$E = (C_{sg} \times Q_{sd}) / O_{cc} \text{ (Eq. 2)}$$

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

C<sub>sg</sub> = average hourly concentration of NOX exiting the steam generating unit, ng/dscm (lb/dscf)

Q<sub>sg</sub> = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

O<sub>cc</sub> = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(ii) The continuous emissions monitoring system specified under Sec. 60.49Da for measuring NOX and oxygen shall be used to determine the average hourly NOX concentrations (C<sub>sg</sub>). The continuous flow monitoring system specified in Sec. 60.49Da(l) shall be used to determine the volumetric flow rate (Q<sub>sg</sub>) of the exhaust gas. The sampling site shall be located at the outlet from the steam generating unit. Data from a continuous flow monitoring system certified (or recertified) following procedures specified in 40 CFR 75.20, meeting the quality assurance and quality control requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used.

(iii) The continuous monitoring system specified under Sec. 60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (O<sub>cc</sub>), which is the combined output from the combustion turbine and the steam generating unit.

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(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in Sec. 60.49Da(l), determine the mass rate (lb/hr) of NOX emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of 40 CFR part 75. If this compliance option is selected, the emission rate (E) of NOX shall be computed using Equation 3 of this section:

$$E = (ER_{sg} \times H_{cc}) / Occ \text{ (Eq. 3)}$$

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

ER<sub>sg</sub> = average hourly emission rate of NOX exiting the steam generating unit heat input calculated using appropriate F-factor as described in Method 19, ng/J (lb/million Btu)

H<sub>cc</sub> = average hourly heat input rate of entire combined cycle unit, J/hr (million Btu/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable NOX emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) Compliance provisions for sources subject to Sec. 60.45Da. The owner or operator of an affected facility subject to Sec. 60.45Da (new sources constructed, modified, or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of Sec. 60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of Sec. 60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in Sec. 60.49Da(k). Compliance with the applicable standard under Sec. 60.45Da is determined on a 12-month rolling average basis.

(m) Compliance provisions for sources subject to Sec. 60.43Da(i)(1)(i) or (j)(1)(i). The owner or operator of an affected facility subject to Sec. 60.43Da(i)(1)(i) or (j)(1)(i) shall calculate SO<sub>2</sub> emissions by multiplying the average hourly SO<sub>2</sub> output concentration, measured according to the provisions of Sec. 60.49Da(b), by the average hourly flow rate, measured according to the provisions of Sec. 60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of Sec. 60.49Da(k).

(n) Compliance provisions for sources subject to Sec. 60.42Da(c)(1). The owner or operator of an affected facility subject to Sec. 60.42Da(c)(1) shall calculate particulate matter emissions by multiplying the average hourly particulate matter output concentration, measured according to the provisions of Sec. 60.49Da(t), by the average hourly flow rate, measured according to the provisions of Sec. 60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of Sec. 60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) Compliance provisions for sources subject to Sec. 60.42Da(c)(2) or (d). Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) Conduct an initial performance test according to the requirements in Sec. 60.50Da to demonstrate compliance by the applicable date specified in Sec. 60.8(a) and, thereafter, conduct the performance test annually, and

(2) An owner or operator must use opacity monitoring equipment as an indicator of continuous particulate matter control device performance and demonstrate compliance with Sec. 60.42Da(b). In addition, baseline parameters shall be established as the highest hourly opacity average measured during the performance test. If any hourly average opacity measurement is more than 110 percent of the baseline level, the owner or operator will conduct another

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performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test. The new baseline shall not exceed the opacity limit specified in Sec. 60.42Da(b), and

(3) An owner or operator using an ESP to comply with the applicable emission limits shall use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP. Baseline parameters shall be established as average rates measured during the performance test. If a 3-hour average voltage and secondary current average deviates more than 10 percent from the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test, and

(4) An owner or operator using a fabric filter to comply with the applicable emission limits shall install, calibrate, maintain, and continuously operate a bag leak detection system according to paragraphs (o)(4)(i) through (viii) of this section.

(i) Install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(ii) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA-454/R-98-015, September 1997.

(iii) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(iv) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(v) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(vi) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel. Corrective actions must be initiated within 1 hour of a bag leak detection system alarm. If the alarm is engaged for more than 5 percent of the total operating time on a 30-day rolling average, a performance test must be performed within 60 days to demonstrate compliance.

(vii) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(viii) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors, and

(5) An owner or operator of a modified affected source electing to meet the emission limitations in Sec. 60.42Da(d) shall determine the percent reduction in particulate matter by using the emission rate for particulate matter determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a continuous emission monitoring system measuring particulate matter emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a continuous monitoring system measuring particulate matter. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each continuous emission monitor shall be installed, certified, operated, and maintained according to the requirements in Sec. 60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under Sec. 60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

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(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19, section 4.1.

(5) At a minimum, valid continuous monitoring system hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/h, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under Sec. 60.13(e)(2) of subpart A of this part.

(7) All valid continuous monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(5) of this section are not met.

(8) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 90 percent of all operating hours per 30-day rolling average.

#### Sec. 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility that qualifies under the numerical limit provisions of Sec. 60.43Da(d), (i), (j), or (k) sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(c) (1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of Sec. 60.51Da. Data reported to meet the requirements of Sec. 60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency

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conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) (1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph Sec. 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under Sec. 60.48Da. The 1-hour averages are calculated using the data points required under Sec. 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 shall be used to determine the SO<sub>2</sub> concentration at the same location as the SO<sub>2</sub> monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 shall be used to determine the NO<sub>x</sub> concentration at the same location as the NO<sub>x</sub> monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O<sub>2</sub> or CO<sub>2</sub> concentration at the same location as the O<sub>2</sub> or CO<sub>2</sub> monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (lb/million Btu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under Sec. 60.13(c) and calibration checks under Sec. 60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7, as applicable, shall be used to determine O<sub>2</sub>, SO<sub>2</sub>, and NO<sub>x</sub> concentrations respectively.

(2) SO<sub>2</sub> or NO<sub>x</sub> (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N<sub>2</sub>, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

| Fossil fuel      | Span value for<br>nitrogen oxides<br>(ppm) |
|------------------|--------------------------------------------|
| Gas.....         | 500                                        |
| Liquid.....      | 500                                        |
| Solid.....       | 1,000                                      |
| Combination..... | 500 (x+y)+1,000z                           |

where:

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x is the fraction of total heat input derived from gaseous fossil fuel,

y is the fraction of total heat input derived from liquid fossil fuel, and

z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under Sec. 60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990]

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under Sec. 60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under Sec. 60.42Da, Sec. 60.43Da, Sec. 60.44Da, or Sec. 60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B and procedure 1 of appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of 40 CFR part 75.



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(o) The owner or operator of a duct burner, as described in Sec. 60.41Da, which is subject to the NOX standards of Sec. 60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a continuous emissions monitoring system to measure NOX emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in Sec. 60.45Da shall install and operate a continuous emissions monitoring system (CEMS) to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to Sec. 75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of Sec. 60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in Sec. 60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in Sec. 60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of Sec. 60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of Sec. 60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in Sec. 72.2 of this chapter) to monitor Hg concentration, according to the procedures described in Sec. 75.15 of this chapter and appendix K to part 75 of this chapter.

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(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of Sec. 75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in Sec. 75.11(b) or Sec. 75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (e.g., calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of Sec. 60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of Sec. 60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing record keeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under Sec. 60.42Da(c)(1) shall install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under Sec. 60.42Da(c)(2) may install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section in lieu of the requirements in Sec. 60.48Da(o).

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1) or (2) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in Sec. 60.48Da(o).

(1) A continuous monitoring system for measuring particulate matter emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under Sec. 60.42Da(a)(1) or Sec. 60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section.

(2) The affected source burns only oil that contains no more than 0.15 weight percent sulfur or liquid or gaseous fuels that when combusted without sulfur dioxide emission control, have a sulfur dioxide emissions rate equal to or less than or equal to 65 ng/J (0.15 lb/MMBtu) heat input.

(v) The owner or operator of an affected facility using a continuous emission monitoring system measuring particulate matter emissions to meet requirements of this subpart shall install, certify, operate, and maintain the continuous monitoring system as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the continuous monitoring system according to the applicable requirements of Sec. 60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and conducting performance tests using the following test methods.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

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(ii) For oxygen (or carbon dioxide), EPA Reference Method 3, 3A, or 3B, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

**Sec. 60.50Da Compliance determination procedures and methods.**

(a) In conducting the performance tests required in Sec. 60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in Sec. 60.8(b). Section 60.8(f) does not apply to this section for SO<sub>2</sub> and NO<sub>x</sub>. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in Sec. 60.42Da as follows:

(1) The dry basis F factor (O<sub>2</sub>) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particulate matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O<sub>2</sub> concentration. The O<sub>2</sub> sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O<sub>2</sub> traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O<sub>2</sub> traverse points. If the grab sampling procedure is used, the O<sub>2</sub> concentration for the run shall be the arithmetic mean of the sample O<sub>2</sub> concentrations at all traverse points.

(3) Method 9 and the procedures in Sec. 60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO<sub>2</sub> standards in Sec. 60.43Da as follows:

(1) The percent of potential SO<sub>2</sub> emissions (%P<sub>s</sub>) to the atmosphere shall be computed using the following equation:

$$\%P_s = [(100 - \%R_f)(100 - \%R_g)]/100$$

where:

%P<sub>s</sub> = percent of potential SO<sub>2</sub> emissions, percent.

%R<sub>f</sub> = percent reduction from fuel pretreatment, percent.

%R<sub>g</sub> = percent reduction by SO<sub>2</sub> control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction (%R<sub>f</sub> of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrosulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO<sub>2</sub> reduction (%R<sub>g</sub>) of any SO<sub>2</sub> control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO<sub>2</sub> control device and the average SO<sub>2</sub> input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in Sec. 60.49Da (b) and (d) shall be used to determine the concentrations of SO<sub>2</sub> and CO<sub>2</sub> or O<sub>2</sub>.

(d) The owner or operator shall determine compliance with the NO<sub>x</sub> standard in Sec. 60.44Da as follows:

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- (1) The appropriate procedures in Method 19 shall be used to determine the emission rate of  $\text{NO}_x$ .
- (2) The continuous monitoring system in Sec. 60.49Da (c) and (d) shall be used to determine the concentrations of  $\text{NO}_x$  and  $\text{CO}_2$  or  $\text{O}_2$ .
- (e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:
- (1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of  $160^\circ\text{C}$  ( $320^\circ\text{F}$ ). The procedures of Secs. 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.
- (2) The  $F_c$  factor ( $\text{CO}_2$ ) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of Sec. 60.46(d)(1). The  $\text{CO}_2$  shall be determined in the same manner as the  $\text{O}_2$  concentration.
- (f) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as  $17 \text{ ng/J}$  ( $0.04 \text{ lb/million Btu}$ ) heat input.
- (g) For the purposes of determining compliance with the emission limits in Sec. 60.45Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus half of the equivalent electrical energy in the unit's process stream.
- (1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (i.e., 250 million Btu/hr input to a electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit; 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 million Btu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).
- (2) Use the Equation 1 of this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$\text{ER}_{\text{cogen}} = \frac{M}{(V_{\text{grid}} + 0.75 \times V_{\text{process}})} \quad (\text{Eq. 1})$$

Where:

$\text{ER}_{\text{cogen}}$  = Cogeneration Hg emission rate over a compliance period in lb/MWh;

$E$  = Mass of Hg emitted from the stack over the same compliance period (lb);

$V_{\text{grid}}$  = Amount of energy sent to the grid over the same compliance period (MWh); and

$V_{\text{process}}$  = Amount of energy converted to steam for process use over the same compliance period (MWh).

- (h) The owner or operator shall determine compliance with the Hg limit in Sec. 60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in Sec. 60.8(a). The required continuous monitoring systems must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the continuous monitoring systems for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in Sec. 60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic

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average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in pounds (lb), using either Equation 2 in paragraph (h)(2)(i)(A) of this section or Equation 3 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 4 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 2 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K C_h Q_h t_h \quad (\text{Eq. 2})$$

Where:

$E_h$  = Hg mass emissions for the hour, (lb)

$K$  = Units conversion constant,  $6.24 \times 10^{-11}$  lb-scm/[mu]g-scf

$C_h$  = Hourly Hg concentration, wet basis, ([mu]g/scm)

$Q_h$  = Hourly stack gas volumetric flow rate, (scfh)

$t_h$  = Unit operating time, i.e., the fraction of the hour for which the unit operated. For example,  $t_h = 0.50$  for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use

Equation 3 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K C_h Q_h t_h (1 - B_{ws}) \quad (\text{Eq. 3})$$

Where:

$E_h$  = Hg mass emissions for the hour, (lb)

$K$  = Units conversion constant,  $6.24 \times 10^{-11}$  lb-scm/[mu]g-scf

$C_h$  = Hourly Hg concentration, dry basis, ([mu]g/dscm)

$Q_h$  = Hourly stack gas volumetric flow rate, (scfh)

$t_h$  = Unit operating time, i.e., the fraction of the hour for which the unit operated

$B_{ws}$  = Stack gas moisture content, expressed as a decimal fraction (e.g., for 8 percent H<sub>2</sub>O,  $B_{ws} = 0.08$ )

(C) Use Equation 4, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 2 or 3 (as applicable):

$$M = \sum_{h=1}^n E_h \quad (\text{Eq. 4})$$

Where:

$M$  = Total Hg mass emissions for the month, (lb)

$E_h$  = Hg mass emissions for hour "h", from Equation 2 or 3 of this section, (lb)

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n = The number of unit operating hours in the month with valid CEM and electrical output data, excluding hours of unit startup, shutdown and malfunction

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 5, below. For a cogeneration unit, use Equation 1 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \quad (\text{Eq. 5})$$

Where:

ER = Monthly Hg emission rate, (lb/MWh)

M = Total mass of Hg emissions for the month, from Equation 4, above, (lb)

P = Total electrical output for the month, for the hours used to calculate M, (MWh)

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 6 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=1}^{12} (ER)_i n_i}{\sum_{i=1}^{12} n_i} \quad (\text{Eq. 6})$$

Where:

E<sub>avg</sub> = Weighted 12-month rolling average Hg emission rate, lb/MWh)

(ER)<sub>i</sub> = Monthly Hg emission rate, for month "i", (lb/MWh)

n = The number of unit operating hours in month "i" with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in Sec. 75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 3 through 5 of this section, except that for a particular pair of sorbent traps, Ch in Equation 3 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride (Hg[deg] or HgCl<sub>2</sub>) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using HgCl<sub>2</sub> standards, as described in section 8.3 of Performance Specification 12-A in appendix B to this part (note: Hg[deg] standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

**Sec. 60.51Da Reporting requirements.**

(a) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

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(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

- (1) Calendar date.
- (2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.
- (3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.
- (4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.
- (5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO<sub>2</sub> only), emergency conditions (SO<sub>2</sub> only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.
- (6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
- (7) Identification of times when hourly averages have been obtained based on manual sampling methods.
- (8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.
- (9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by Sec. 60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of Sec. 60.48Da(h) is reported to the Administrator for that 30-day period:

- (1) The number of hourly averages available for outlet emission rates ( $n_o$ ) and inlet emission rates ( $n_i$ ) as applicable.
- (2) The standard deviation of hourly averages for outlet emission rates ( $s_o$ ) and inlet emission rates ( $s_i$ ) as applicable.
- (3) The lower confidence limit for the mean outlet emission rate ( $E_o^*$ ) and the upper confidence limit for the mean inlet emission rate ( $E_i^*$ ) as applicable.
- (4) The applicable potential combustion concentration.
- (5) The ratio of the upper confidence limit for the mean outlet emission rate ( $E_o^*$ ) and the allowable emission rate ( $E_{std}$ ) as applicable.

(d) If any standards under Sec. 60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

- (1) Indicating if emergency conditions existed and requirements under Sec. 60.48Da(d) were met during each period, and
- (2) Listing the following information:
  - (i) Time periods the emergency condition existed;
  - (ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;
  - (iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;
  - (iv) Percent reduction in emissions achieved;
  - (v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

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(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under Sec. 60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

- (1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of Sec. 60.50Da and Method 19 (appendix A); and
- (2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

- (1) Company name and address;
- (2) Date of report and beginning and ending dates of the reporting period;
- (3) The applicable Hg emission limit (lb/MWh); and
- (4) For each month in the reporting period:
  - (i) The number of unit operating hours;
  - (ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;
  - (iii) The monthly Hg emission rate (lb/MWh);
  - (iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and
  - (v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

- (1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.
- (2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.
- (3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.
- (4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under Sec. 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under Sec. 60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A of this part to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.



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(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO<sub>2</sub> and/or NO<sub>x</sub> and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

**Sec. 60.52Da Recordkeeping requirements.**

The owner or operator of an affected facility subject to the emissions limitations in Sec. 60.45Da or Sec. 60.46Da shall provide notifications in accordance with Sec. 60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of Sec. 60.7(f).

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**SUBPART GG - STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES**

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000; 69 FR 41346, July 8, 2004]

In accordance with Rule 62-204.800(8), F.A.C., the following emissions units are subject to the applicable requirements of 40 CFR 60 Subpart A, General Provisions. For these requirements, the original rule numbering has been retained.

| EU No.  | Brief Description                                                         |
|---------|---------------------------------------------------------------------------|
| 001-004 | Four nominal 170 MW simple cycle combustion turbine-electrical generators |

**§ 60.330 Applicability and designation of affected facility.**

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of § 60.332.

**§ 60.331 Definitions.**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.

(g) *ISO standard day conditions* means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) *Base load* means the load level at which a gas turbine is normally operated.

(k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) *A Metropolitan Statistical Area or MSA* as defined by the Department of Commerce.

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- (n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.
- (o) *Garrison facility* means any permanent military installation.
- (p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.
- (q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.
- (r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.
- (s) *Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.
- (t) *Excess emissions* means a specified averaging period over which either:
- (1) The NO<sub>x</sub> emissions are higher than the applicable emission limit in Sec. 60.332;
  - (2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in Sec. 60.333; or
  - (3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.
- (u) *Natural gas* means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.
- (v) *Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.
- (w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.
- (x) *Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.
- (y) *Unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

**§ 60.332 Standard for nitrogen oxides.**

- (a) On and after the date on which the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

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(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO<sub>x</sub> emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO<sub>x</sub> emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150 \frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO<sub>x</sub> emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO<sub>x</sub> emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO<sub>x</sub> allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO<sub>x</sub> emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under Sec. 60.8 as follows:

| -----                             |                                 |
|-----------------------------------|---------------------------------|
| Fuel-bound nitrogen (% by weight) | F (NO <sub>x</sub> % by volume) |
| -----                             |                                 |
| N ≤ 0.015.....                    | 0                               |
| 0.015 < N ≤ 0.1.....              | 0.04(N)                         |
| 0.1 < N ≤ 0.25.....               | 0.004 + 0.0067(N - 0.1)         |
| N > 0.25.....                     | 0.005                           |
| -----                             |                                 |

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be

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approved for use by the Administrator before the initial performance test required by Sec. 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in § 60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO<sub>x</sub> emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

**§ 60.333 Standard for sulfur dioxide.**

On and after the date on which the performance test required to be conducted by § 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

**§ 60.334 Monitoring of operations.**

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control

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NO<sub>x</sub> emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO<sub>x</sub> emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO<sub>x</sub> and O<sub>2</sub> monitors. As an alternative, a CO<sub>2</sub> monitor may be used to adjust the measured NO<sub>x</sub> concentrations to 15 percent O<sub>2</sub> by either converting the CO<sub>2</sub> hourly averages to equivalent O<sub>2</sub> concentrations using Equation F-14a or F-14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O<sub>2</sub>, or by using the CO<sub>2</sub> readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO<sub>x</sub> and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO<sub>x</sub>) and a percent O<sub>2</sub> basis for oxygen; or

(ii) On a ppm at 15 percent O<sub>2</sub> basis; or

(iii) On a ppm basis (for NO<sub>x</sub>) and a percent CO<sub>2</sub> basis (for a CO<sub>2</sub> monitor that uses the procedures in Method 20 to correct the NO<sub>x</sub> data to 15 percent O<sub>2</sub>).

(2) As specified in Sec. 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in Sec. 60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO<sub>x</sub> and diluent, the data acquisition and handling system must calculate and record the hourly NO<sub>x</sub> emissions in the units of the applicable NO<sub>x</sub> emission standard under Sec. 60.332(a), i.e., percent NO<sub>x</sub> by volume, dry basis, corrected to 15 percent O<sub>2</sub> and International Organization for Standardization (ISO) standard conditions (if required as given in Sec. 60.335(b)(1)). For any hour in which the hourly average O<sub>2</sub> concentration exceeds 19.0 percent O<sub>2</sub>, a diluent cap value of 19.0 percent O<sub>2</sub> may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (H<sub>o</sub>), minimum ambient temperature (T<sub>a</sub>), and minimum combustor inlet absolute pressure (P<sub>o</sub>) into the ISO correction equation.

(iii) If the owner or operator has installed a NO<sub>x</sub> CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in Sec. 60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO<sub>x</sub> emissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority

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approval of a procedure for monitoring compliance with the applicable NO<sub>x</sub> emission limit under Sec. 60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO<sub>x</sub> emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO<sub>x</sub> CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO<sub>x</sub> emissions, may, but is not required to, elect to use a NO<sub>x</sub> CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO<sub>x</sub> emissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO<sub>x</sub> formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO<sub>x</sub> mode.

(3) For any turbine that uses SCR to reduce NO<sub>x</sub> emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO<sub>x</sub> emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in Sec. 75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in Sec. 75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under Sec. 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO<sub>x</sub> emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in Sec. 75.19 of this chapter or the NO<sub>x</sub> emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in Sec. 75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in Sec. 60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see Sec. 60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator

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to calculate STD in Sec. 60.332). The nitrogen content of the fuel shall be determined using methods described in Sec. 60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in Sec. 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) Gaseous fuel. Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) Custom schedules. Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in Sec. 60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.



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(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (i.e., the maximum total sulfur content of natural gas as defined in Sec. 60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with Sec. 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under Sec. 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with Sec. 60.332, as established during the performance test required in Sec. 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

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(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in Sec. 60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO<sub>x</sub> and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO<sub>x</sub> concentration exceeds the applicable emission limit in Sec. 60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO<sub>x</sub> concentration" is the arithmetic average of the average NO<sub>x</sub> concentration measured by the CEMS for a given hour (corrected to 15 percent O<sub>2</sub> and, if required under Sec. 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO<sub>x</sub> concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO<sub>x</sub> concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO<sub>x</sub> emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

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(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in § 60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in § 60.332(k) is in effect shall be included in the report required in § 60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under Sec. 60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

**Sec. 60.335 Test methods and procedures.**

(a) The owner or operator shall conduct the performance tests required in Sec. 60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see Sec. 60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO<sub>x</sub> and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO<sub>x</sub> and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO<sub>x</sub> concentrations, normalized to 15 percent O<sub>2</sub>, is within 10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO<sub>x</sub> concentration during the stratification test; or

(B) If each of the individual traverse point NO<sub>x</sub> concentrations, normalized to 15 percent O<sub>2</sub>, is within 5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in Sec. 60.332 and shall meet the performance test requirements of Sec. 60.8 as follows:

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(1) For each run of the performance test, the mean nitrogen oxides emission concentration ( $\text{NO}_{\text{Xo}}$ ) corrected to 15 percent  $\text{O}_2$  shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$\text{NO}_\text{X} = (\text{NO}_{\text{Xo}})(P_r/P_o)^{0.5} e^{19(H_o - 0.00633)} (288[\text{deg}]\text{K}/T_a)^{1.53}$$

Where:

$\text{NO}_\text{X}$  = emission concentration of  $\text{NO}_\text{X}$  at 15 percent  $\text{O}_2$  and ISO standard ambient conditions, ppm by volume, dry basis,

$\text{NO}_{\text{Xo}}$  = mean observed  $\text{NO}_\text{X}$  concentration, ppm by volume, dry basis, at 15 percent  $\text{O}_2$ ,

$P_r$  = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

$P_o$  = observed combustor inlet absolute pressure at test, mm Hg,

$H_o$  = observed humidity of ambient air, g  $\text{H}_2\text{O}/\text{g}$  air,

$e$  = transcendental constant, 2.718, and

$T_a$  = ambient temperature,  $[\text{deg}]\text{K}$ .

(2) The 3-run performance test required by Sec. 60.8 must be performed within 5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in Sec. 60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine  $\text{NO}_\text{X}$  emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable  $\text{NO}_\text{X}$  emission limit in Sec. 60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control  $\text{NO}_\text{X}$  with no additional post-combustion  $\text{NO}_\text{X}$  control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with Sec. 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference, see Sec. 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable Sec. 60.332  $\text{NO}_\text{X}$  emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in Sec. 60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in Sec. 60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a  $\text{NO}_\text{X}$  CEMS under Sec. 60.334(e), then the initial performance test required under Sec. 60.8 may be done in the following alternative manner:

- (i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.
- (ii) Use the test data both to demonstrate compliance with the applicable  $\text{NO}_\text{X}$  emission limit under Sec. 60.332 and to provide the required reference method data for the RATA of the CEMS described under Sec. 60.334(b).

**SECTION 5. APPENDIX F**  
**NSPS Subpart GG Provisions**

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(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under Sec. 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NOX emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in Sec. 60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597-94 (Reapproved 1999), D6366-99, D4629-02, D5762-02 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under Sec. 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in Sec. 60.8 to ISO standard day conditions.

## SECTION 5. APPENDIX G

### Permit History

Auburndale Energy Complex  
Facility ID No. 1050221

| <u>EU No.</u> | <u>Description</u>                | <u>Permit No.</u>                            | <u>Issue Date</u> | <u>Expiration Date</u> | <u>Extended Date</u> <sup>1,2</sup> | <u>Revised Date(s)</u>                         |
|---------------|-----------------------------------|----------------------------------------------|-------------------|------------------------|-------------------------------------|------------------------------------------------|
| -001          | Combined Cycle Combustion Turbine | AC53-208321/<br>PSD-FL-185<br>1050221-004-AC | 12/14/92          | 10/30/95               | 11/1/96                             | 6/20/94, 3/18/96, 5/22/97<br>2/26/02, xx/xx/xx |
| -002          | Fuel oil storage tanks (2)        |                                              |                   |                        |                                     |                                                |
| -003          | Emergency generators              |                                              |                   |                        |                                     |                                                |
| -004          | Heating units and engines         |                                              |                   |                        |                                     |                                                |
| -005          | Surface coating operations        |                                              |                   |                        |                                     |                                                |
| -006          | Simple Cycle Combustion Turbine   | 1050221-004-AC                               |                   | 4/1/03                 |                                     | 4/29/02                                        |
| -007          | Combustion Turbine                | 1050334-001-AC                               |                   |                        |                                     |                                                |
| -008          | Combustion Turbine                | 1050334-001-AC                               |                   |                        |                                     |                                                |
| -009          | Duct Burner                       | 1050334-001-AC                               |                   |                        |                                     |                                                |
| -010          | Duct Burner                       | 1050334-001-AC                               |                   |                        |                                     |                                                |
| -011          | Cooling Tower                     | 1050334-001-AC                               |                   |                        |                                     |                                                |
| All           | Initial Title V                   | 1050221-002-AV                               |                   |                        |                                     |                                                |
| All           | Title V Renewal                   | 1050221-007-AV                               |                   | 12/31/07               |                                     |                                                |
| All           | Title V Revision                  | 1050221-009-AV                               |                   | 12/31/07               |                                     |                                                |
| All           | Air Construction Permit Mod       | 1050221-010-AC                               |                   |                        |                                     |                                                |

Note: The Osprey Energy Center was originally permitted as Facility ID No. 1050334, but was later merged into Facility ID No. 1050221 with the Auburndale Power Plant and the Auburndale Peak Energy Center

## SECTION 5. APPENDIX H

### Insignificant Emissions Units and Activities

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 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 Rules 62-210.300(3)(a) and (b)1., 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 Rules 62-210.300(3)(a) and (b)1., 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 emissions units and activities listed below are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

1. Comfort heating with a gross maximum heat input of less than one million Btu per hour.
2. Vacuum pumps in laboratory operations.
3. Belt or Drum Sanders having a total sanding surface of five square feet or less and other equipment used exclusively on woods or plastics or their products having a density of 20 pounds per cubic foot or more.
4. Equipment used exclusively for space heating, other than boilers.
5. Laboratory equipment used exclusively for chemical or physical analyses (including fume hoods and vents).
6. Surface coating operations utilizing only coatings containing 5.0 percent or less VOCs, by volume.
7. Degreasing units using heavier-than-air vapors exclusively, except any unit using or emitting any substance classified as a hazardous air pollutant.
8. No. 2 Fuel Oil Truck Unloading Equipment.
9. Oil/Water Separators.
10. Freshwater cooling towers. The cooling towers do not use chromium-based water treatment chemicals.
11. Refrigeration Units.
12. Lube Oil Vents Associated with Rotating Equipment.
13. Lube Oil Tank Vents.
14. Internal combustion engines used for transportation of passengers and freight.
15. Steam cleaning equipment.
16. Fire and safety equipment.
17. Brazing, soldering, or welding equipment.
18. Petroleum Lube Systems
19. Application of fungicide, herbicide, or pesticide
20. Non-halogenated solvent storage and cleaning operation, provided the solvents contain none of the hazardous air pollutants listed in Rule 62-210.200, F.A.C.
21. Vehicle refueling operations and associated fuel storage
22. Storage tanks less than 250 gallons
23. General Plant maintenance activities including, but no limited to, welding, grinding, and general vehicle repair (excluding air-conditioning systems).
24. Water and wastewater treatment equipment
25. Turbine Vapor Extractor
26. Wet surface air coolers
27. Sand Blasting and abrasive grit blasting where temporary total enclosures are used to contain particulate matter emissions.
28. Vehicular Traffic on plant roadways and grounds
29. Architectural (equipment) maintenance painting
30. One (1) 1,250 KW emergency generator diesel engine
31. One (1) 265 HP fire water pump diesel engine
32. Two fuel storage tanks

**SECTION 5. APPENDIX I**  
**Unregulated Emissions Units**

An "unregulated emissions unit" is 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 otherwise applicable unit-specific emissions or work practice standards (e.g., recordkeeping requirements for small storage tanks under 40 CFR 60, Subpart Kb). All fugitive emissions not subject to unit-specific work practice standards may be included in the application as one or more separate unregulated emissions units.

The following emissions units are considered unregulated emissions units.

| <b>EU No.</b>                 | <b>Brief Description</b>                                          |
|-------------------------------|-------------------------------------------------------------------|
| <b>Auburndale Power Plant</b> |                                                                   |
| 002                           | Fuel oil storage tanks                                            |
| 003                           | Emergency generators [Rule 62-210.300(3)(a), F.A.C.]              |
| 004                           | Heating units and engines [Rule 62-210.300(3)(a), F.A.C.]         |
| 005                           | Surface coating operations [Rule 62-210.300(3)(a), F.A.C.]        |
| 011                           | Cooling tower consisting of 8 cells with individual exhaust fans. |

**1. Drift Eliminators for PM/PM<sub>10</sub> Emissions.** Drift eliminators shall be installed on the cooling tower (EU-011) to achieve a maximum designed drift rate of 0.002 gallons/100 gallons of recirculation water flow rate. The permittee shall maintain a certification that the installed equipment meets this design specification. [PSD-FL-287]



## SECTION 5. APPENDIX V

### Title V Conditions

#### Chapter 62-4, F.A.C.

1. **Not federally enforceable. General Prohibition.** Any stationary installation which will reasonably be expected to be a source of pollution shall not be operated, maintained, constructed, expanded, or modified without the appropriate and valid permits issued by the Department, unless the source is exempted by Department rule. The Department may issue a permit only after it receives reasonable assurance that the installation will not cause pollution in violation of any of the provisions of Chapter 403, F.S., or the rules promulgated thereunder. A permitted installation may only be operated, maintained, constructed, expanded or modified in a manner that is consistent with the terms of the permit.

[Rule 62-4.030, Florida Administrative Code (F.A.C.); and, Section 403.087, Florida Statute (F.S.)]

2. **Not federally enforceable. Procedures to Obtain Permits and Other Authorizations: Applications.**

(1) Any person desiring to obtain a permit from the Department shall apply on forms prescribed by the Department and shall submit such additional information as the Department by law may require.

(2) All applications and supporting documents shall be filed in quadruplicate with the Department.

(3) To ensure protection of public health, safety, and welfare, any construction, modification, or operation of an installation which may be a source of pollution, shall be in accordance with sound professional engineering practices pursuant to Chapter 471, F.S. All applications for a Department permit shall be certified by a professional engineer registered in the State of Florida except, when the application is for renewal of an air pollution operation permit at a non-Title V source as defined in Rule 62-210.200, F.A.C., or where professional engineering is not required by Chapter 471, F.S. Where required by Chapter 471 or 492, F.S., applicable portions of permit applications and supporting documents which are submitted to the Department for public record shall be signed and sealed by the professional(s) who prepared or approved them.

(4) Processing fees for air construction permits shall be in accordance with Rule 62-4.050(4), F.A.C.

(5) (a) To be considered by the Department, each application must be accompanied by the proper processing fee. The fee shall be paid by check, payable to the Department of Environmental Protection. The fee is non-refundable except as provided in Section 120.60, F.S., and in this section.

(b) When an application is received without the required fee, the Department shall acknowledge receipt of the application and shall immediately notify the applicant by certified mail that the required fee was not received and advise the applicant of the correct fee. The Department shall take no further action until the correct fee is received. If a fee was received by the Department which is less than the amount required, the Department shall return the fee along with the written notification.

(c) Upon receipt of the proper application fee, the permit processing time requirements of Sections 120.60(2) and 403.0876, F.S., shall begin.

(d) If the applicant does not submit the required fee within ten days of receipt of written notification, the Department shall either return the unprocessed application or arrange with the applicant for the pick up of the application.

(e) If an applicant submits an application fee in excess of the required fee, the permit processing time requirements of Sections 120.60(2) and 403.0876, F.S., shall begin upon receipt, and the Department shall refund to the applicant the amount received in excess of the required fee.

(6) Any substantial modification to a complete application shall require an additional processing fee determined pursuant to the schedule set forth in Rule 62-4.050, F.A.C., and shall restart the time requirements of Sections 120.60 and 403.0876, F.S. For purposes of this subsection, the term "substantial modification" shall mean a modification which is reasonably expected to lead to substantially different environmental impacts which require a detailed review.

(7) Modifications to existing permits proposed by the permittee which require substantial changes in the existing permit or require substantial evaluation by the Department of potential impacts of the proposed modifications shall require the same fee as a new application for the same time duration except for modification under Chapter 62-45, F.A.C.

[Rule 62-4.050, F.A.C.]

3. **Standards for Issuing or Denying Permits.** Except as provided at Rule 62-213.460, F.A.C., the issuance of a permit does not relieve any person from complying with the requirements of Chapter 403, F.S., or Department rules.

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## SECTION 5. APPENDIX V

### Title V Conditions

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[Rule 62-4.070(7), F.A.C.]

#### 4. Modification of Permit Conditions.

(1) For good cause and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions and on application of the permittee the Department may grant additional time. For the purpose of this section, good cause shall include, but not be limited to, any of the following: **(also, see Condition No. 38.)**

(a) A showing that an improvement in effluent or emission quality or quantity can be accomplished because of technological advances without unreasonable hardship.

(b) A showing that a higher degree of treatment is necessary to effect the intent and purpose of Chapter 403, F.S.

(c) A showing of any change in the environment or surrounding conditions that requires a modification to conform to applicable air or water quality standards.

(e) Adoption or revision of Florida Statutes, rules, or standards which require the modification of a permit condition for compliance.

(2) A permittee may request a modification of a permit by applying to the Department.

(3) A permittee may request that a permit be extended as a modification of the permit. Such a request must be submitted to the Department in writing before the expiration of the permit. Upon timely submittal of a request for extension, unless the permit automatically expires by statute or rule, the permit will remain in effect until final agency action is taken on the request. For construction permits, an extension shall be granted if the applicant can demonstrate reasonable assurances that, upon completion, the extended permit will comply with the standards and conditions required by applicable regulation. For all other permits, an extension shall be granted if the applicant can demonstrate reasonable assurances that the extended permit will comply with the standards and conditions applicable to the original permit. A permit for which the permit application fee was prorated in accordance with Rule 62-4.050(4)(v), F.A.C., shall not be extended. In no event shall a permit be extended or remain in effect longer than the time limits established by statute or rule.

[Rule 62-4.080, F.A.C.]

5. Renewals. Prior to 180 days before the expiration of a permit issued pursuant to Chapter 62-213, F.A.C., the permittee shall apply for a renewal of a permit using forms incorporated by reference in the specific rule chapter for that kind of permit. A renewal application shall be timely and sufficient. If the application is submitted prior to 180 days before expiration of the permit, it will be considered timely and sufficient. If the renewal application is submitted at a later date, it will not be considered timely and sufficient unless it is submitted and made complete prior to the expiration of the operation permit. When the application for renewal is timely and sufficient, the existing permit shall remain in effect until the renewal application has been finally acted upon by the Department or, if there is court review of the Department's final agency action, until a later date is required by Section 120.60, F.S., provided that, for renewal of a permit issued pursuant to Chapter 62-213, F.A.C., the applicant complies with the requirements of Rules 62-213.420(1)(b)3. and 4., F.A.C.

[Rule 62-4.090, F.A.C.]

#### 6. Suspension and Revocation.

(1) Permits shall be effective until suspended, revoked, surrendered, or expired and shall be subject to the provisions of Chapter 403, F.S., and rules of the Department.

(2) Failure to comply with pollution control laws and rules shall be grounds for suspension or revocation.

(3) A permit issued pursuant to Chapter 62-4, F.A.C., shall not become a vested property right in the permittee. The Department may revoke any permit issued by it if it finds that the permit holder or his agent:

(a) Submitted false or inaccurate information in his application or operational reports.

(b) Has violated law, Department orders, rules or permit conditions.

(c) Has failed to submit operational reports or other information required by Department rules.

(d) Has refused lawful inspection under Section 403.091, F.S.

## SECTION 5. APPENDIX V

### Title V Conditions

(4) No revocation shall become effective except after notice is served by personal services, certified mail, or newspaper notice pursuant to Section 120.60(7), F.S., upon the person or persons named therein and a hearing held if requested within the time specified in the notice. The notice shall specify the provision of the law, or rule alleged to be violated, or the permit condition or Department order alleged to be violated, and the facts alleged to constitute a violation thereof.

[Rule 62-4.100, F.A.C.]

7. **Not federally enforceable.** Financial Responsibility. The Department may require an applicant to submit proof of financial responsibility and may require the applicant to post an appropriate bond to guarantee compliance with the law and Department rules.

[Rule 62-4.110, F.A.C.]

8. Transfer of Permits.

(1) Within 30 days after the sale or legal transfer of a permitted facility, an "Application for Transfer of Permit" (DEP Form 62-1.201(1)) must be submitted to the Department. This form must be completed with the notarized signatures of both the permittee and the proposed new permittee. For air permits, an "Application for Transfer of Air Permit" (DEP Form 62-210.900(7)) shall be submitted.

(2) The Department shall approve the transfer of a permit unless it determines that the proposed new permittee cannot provide reasonable assurances that conditions of the permit will be met. The determination shall be limited solely to the ability of the new permittee to comply with the conditions of the existing permit, and it shall not concern the adequacy of these permit conditions. If the Department proposes to deny the transfer, it shall provide both the permittee and the proposed new permittee a written objection to such transfer together with notice of a right to request a Chapter 120, F.S., proceeding on such determination.

(3) Within 30 days of receiving a properly completed Application for Transfer of Permit form, the Department shall issue a final determination. The Department may toll the time for making a determination on the transfer by notifying both the permittee and the proposed new permittee that additional information is required to adequately review the transfer request. Such notification shall be served within 30 days of receipt of an Application for Transfer of Permit form, completed pursuant to Rule 62-4.120(1), F.A.C. If the Department fails to take action to approve or deny the transfer within 30 days of receipt of the completed Application for Transfer of Permit form, or within 30 days of receipt of the last item of timely requested additional information, the transfer shall be deemed approved.

(4) The permittee is encouraged to apply for a permit transfer prior to the sale or legal transfer of a permitted facility. However, the transfer shall not be effective prior to the sale or legal transfer.

(5) Until this transfer is approved by the Department, the permittee and any other person constructing, operating, or maintaining the permitted facility shall be liable for compliance with the terms of the permit. The permittee transferring the permit shall remain liable for corrective actions that may be required as a result of any violations occurring prior to the sale or legal transfer of the facility.

[Rule 62-4.120, F.A.C.]

9. Plant Operation-Problems. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. (also, see Condition No. 10.)

[Rule 62-4.130, F.A.C.]

10. For purposes of notification to the Department pursuant to Condition No. 9., Condition No. 12.(8), and Rule 62-4.130, F.A.C., Plant Operation-Problems, "immediately" shall mean the same day, if during a workday (i.e., 8:00 a.m. - 5:00 p.m.), or the first business day after the incident, excluding weekends and holidays; and, for purposes of 40 CFR 70.6(a)(3)(iii)(B), "prompt" shall have the same meaning as "immediately". [also, see Conditions Nos. 9. and 12.(8).]

[40 CFR 70.6(a)(3)(iii)(B)]

## SECTION 5. APPENDIX V

### Title V Conditions

11. **Not federally enforceable. Review.** Failure to request a hearing within 14 days of receipt of notice of proposed or final agency action on a permit application or as otherwise required in Chapter 62-103, F.A.C., shall be deemed a waiver of the right to an administrative hearing.

[Rule 62-4.150, F.A.C.]

12. **Permit Conditions.** All permits issued by the Department shall include the following general conditions:

(1) The terms, conditions, requirements, limitations and restrictions set forth in this permit, are "permit conditions" and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

(2) This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

(3) As provided in Subsections 403.987(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in this permit.

(4) This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

(5) This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department.

(6) The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

(7) The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at reasonable times, access to the premises where the permitted activity is located or conducted to:

(a) Have access to and copy any records that must be kept under conditions of the permit;

(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules. Reasonable time may depend on the nature of the concern being investigated.

(8) If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information: (**also, see Condition No. 10.**)

(a) A description of and cause of noncompliance; and

(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

(9) In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be

## SECTION 5. APPENDIX V

### Title V Conditions

used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

(10) The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

(11) This permit is transferable only upon Department approval in accordance with Rule 62-4.120, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

(12) This permit or a copy thereof shall be kept at the work site of the permitted activity.

(14) The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least five (5) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used;
6. The results of such analyses.

(15) When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

[Rules 62-4.160 and 62-213.440(1)(b), F.A.C.]

#### 13. Construction Permits.

(1) No person shall construct any installation or facility which will reasonably be expected to be a source of air pollution without first applying for and receiving a construction permit from the Department unless exempted by statute or Department rule. In addition to the requirements of Chapter 62-4, F.A.C., applicants for a Department Construction Permit shall submit the following as applicable:

(a) A completed application on forms furnished by the Department.

(b) An engineering report covering:

1. Plant description and operations,
2. Types and quantities of all waste material to be generated whether liquid, gaseous or solid,
3. Proposed waste control facilities,
4. The treatment objectives,

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5. The design criteria on which the control facilities are based, and
6. Other information deemed relevant.

Design criteria submitted pursuant to Rule 62-4.210(1)(b)5., F.A.C., shall be based on the results of laboratory and pilot-plant scale studies whenever such studies are warranted. The design efficiencies of the proposed waste treatment facilities and the quantities and types of pollutants in the treated effluents or emissions shall be indicated. Work of this nature shall be subject to the requirements of Chapter 471, F.S. Where confidential records are involved, certain information may be kept confidential pursuant to Section 403.111, F.S.

(c) The owners' written guarantee to meet the design criteria as accepted by the Department and to abide by Chapter 403, F.S., and the rules of the Department as to the quantities and types of materials to be discharged from the installation. The owner may be required to post an appropriate bond or other equivalent evidence of financial responsibility to guarantee compliance with such conditions in instances where the owner's financial resources are inadequate or proposed control facilities are experimental in nature.

(2) The construction permit may contain conditions and an expiration date as determined by the Secretary or the Secretary's designee.

(3) When the Department issues a permit to construct, the permittee shall be allowed a period of time, specified in the permit, to construct, and to operate and test to determine compliance with Chapter 403, F.S., and the rules of the Department and, where applicable, to apply for and receive an operation permit. The Department may require tests and evaluations of the treatment facilities by the permittee at his/her expense.

[Rule 62-4.210, F.A.C.]

14. **Not federally enforceable. Operation Permit for New Sources.** To properly apply for an operation permit for new sources the applicant shall submit the appropriate fee and certification that construction was completed, noting any deviations from the conditions in the construction permit and test results where appropriate.

[Rule 62-4.220, F.A.C.]

#### Chapters 28-106 and 62-110, F.A.C.

15. Public Notice, Public Participation, and Proposed Agency Action. The permittee shall comply with all of the requirements for public notice, public participation, and proposed agency action pursuant to Rules 62-110.106 and 62-210.350, F.A.C.

[Rules 62-110.106, 62-210.350 and 62-213.430(1)(b), F.A.C.]

16. Administrative Hearing. The permittee shall comply with all of the requirements for a petition for administrative hearing or waiver of right to administrative proceeding pursuant to Rules 28-106.201, 28-106.301 and 62-110.106, F.A.C.

[Rules 28-106.201, 28-106.301 and 62-110.106, F.A.C.]

#### Chapter 62-204, F.A.C.

17. Asbestos. This permit does not authorize any demolition or renovation of the facility or its parts or components which involves asbestos removal. This permit does not constitute a waiver of any of the requirements of Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, National Emission Standard for Asbestos, adopted and incorporated by reference in Rule 62-204.800, F.A.C. Compliance with Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, Section 61.145, is required for any asbestos demolition or renovation at the source.

[40 CFR 61; Rule 62-204.800, F.A.C.; and, Chapter 62-257, F.A.C.]

#### Chapter 62-210, F.A.C.

18. Permits Required. Unless exempted from permitting pursuant to Rule 62-210.300(3)(a) or (b), F.A.C., or Rule 62-4.040, F.A.C., or unless specifically authorized by provision of Rule 62-210.300(4), F.A.C., or Rule 62-213.300, F.A.C., the owner or operator of any facility or emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain an appropriate permit from the Department prior to beginning construction, reconstruction pursuant to 40 CFR 60.15 or 63.2, modification, or the addition of pollution control equipment; or to authorize initial or continued operation of the emissions unit; or to establish a PAL or Air Emissions Bubble. All emissions limitations, controls, and other

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requirements imposed by such permits shall be at least as stringent as any applicable limitations and requirements contained in or enforceable under the State Implementation Plan (SIP) or that are otherwise federally enforceable. Except as provided at Rule 62-213.460, F.A.C., issuance of a permit does not relieve the owner or operator of a facility or an emissions unit from complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law.

#### (1) Air Construction Permits.

(a) Unless exempt from permitting pursuant to Rule 62-210.300(3)(a) or (b), F.A.C., or Rule 62-4.040, F.A.C., an air construction permit shall be obtained by the owner or operator of any proposed new, reconstructed, or modified facility or emissions unit, or any new pollution control equipment prior to the beginning of construction, reconstruction pursuant to 40 CFR 60.15 or 63.2, or modification of the facility or emissions unit or addition of the pollution control equipment; or to establish a PAL; in accordance with all applicable provisions of Chapter 62-210, F.A.C., Chapter 62-212, F.A.C., and Chapter 62-4, F.A.C. Except as provided under Rule 62-213.415, F.A.C., the owner or operator of any facility seeking to create or change an air emissions bubble shall obtain an air construction permit in accordance with all the applicable provisions of Chapter 62-210, F.A.C., Chapters 62-212 and 62-4, F.A.C. The construction permit shall be issued for a period of time sufficient to allow construction, reconstruction or modification of the facility or emissions unit or addition of the air pollution control equipment; and operation while the owner or operator of the new, reconstructed or modified facility or emissions unit or the new pollution control equipment is conducting tests or otherwise demonstrating initial compliance with the conditions of the construction permit.

(b) Notwithstanding the expiration of an air construction permit, all limitations and requirements of such permit that are applicable to the design and operation of the permitted facility or emissions unit shall remain in effect until the facility or emissions unit is permanently shut down, except for any such limitation or requirement that is obsolete by its nature (such as a requirement for initial compliance testing) or any such limitation or requirement that is changed in accordance with the provisions of Rule 62-210.300(1)(b)1., F.A.C. Either the applicant or the Department can propose that certain conditions be considered obsolete. Any conditions or language in an air construction permit that are included for informational purposes only, if they are transferred to the air operation permit, shall be transferred for informational purposes only and shall not become enforceable conditions unless voluntarily agreed to by the permittee or otherwise required under Department rules.

1. Except for those limitations or requirements that are obsolete, all limitations and requirements of an air construction permit shall be included and identified in any air operation permit for the facility or emissions unit. The limitations and requirements included in the air operation permit can be changed, and thereby superseded, through the issuance of an air construction permit, federally enforceable state air operation permit, federally enforceable air general permit, or Title V air operation permit; provided, however, that:

- a. Any change that would constitute an administrative correction may be made pursuant to Rule 62-210.360, F.A.C.;
- b. Any change that would constitute a modification, as defined at Rule 62-210.200, F.A.C., shall be accomplished only through the issuance of an air construction permit; and
- c. Any change in a permit limitation or requirement that originates from a permit issued pursuant to 40 CFR 52.21, Rule 62-204.800(1)(d)2., F.A.C., Rule 62-212.400, F.A.C., Rule 62-212.500, F.A.C., or any former codification of Rule 62-212.400 or Rule 62-212.500, F.A.C., shall be accomplished only through the issuance of a new or revised air construction permit under Rule 62-204.800(1)(d)2., Rule 62-212.400 or Rule 62-212.500, F.A.C., as appropriate.

2. The force and effect of any change in a permit limitation or requirement made in accordance with the provisions of Rule 62-210.300(1)(b)1., F.A.C., shall be the same as if such change were made to the original air construction permit.

3. Nothing in Rule 62-210.300(1)(b), F.A.C., shall be construed as to allow operation of a facility or emissions unit without a valid air operation permit.

(2) Air Operation Permits. Upon expiration of the air operation permit for any existing facility or emissions unit, subsequent to construction or modification, or subsequent to the creation of or change to a bubble, and demonstration of compliance with the conditions of the construction permit for any new or modified facility or emissions unit, any air emissions bubble, or as otherwise provided in Chapter 62-210, F.A.C., or Chapter 62-213, F.A.C., the owner or operator of such facility or emissions unit shall obtain a renewal air operation permit, an initial air operation permit or air general

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permit, or an administrative correction or revision of an existing air operation permit, whichever is appropriate, in accordance with all applicable provisions of Chapter 62-210, F.A.C., Chapter 62-213, F.A.C., and Chapter 62-4, F.A.C.

(a) **Minimum Requirements for All Air Operation Permits.** At a minimum, a permit issued pursuant to this subsection shall:

1. Specify the manner, nature, volume and frequency of the emissions permitted, and the applicable emission limiting standards or performance standards, if any;

2. Require proper operation and maintenance of any pollution control equipment by qualified personnel, where applicable in accordance with the provisions of any operation and maintenance plan required by the air pollution rules of the Department.

3. Contain an effective date stated in the permit which shall not be earlier than the date final action is taken on the application and be issued for a period, beginning on the effective date, as provided below.

a. The operation permit for an emissions unit which is in compliance with all applicable rules and in operational condition, and which the owner or operator intends to continue operating, shall be issued or renewed for a five-year period, except that, for Title V sources subject to Rule 62-213.420(1)(a)1., F.A.C., operation permits shall be extended until 60 days after the due date for submittal of the facility's Title V permit application as specified in Rule 62-213.420(1)(a)1., F.A.C.

b. Except as provided in Rule 62-210.300(2)(a)3.d., F.A.C., the operation permit for an emissions unit which has been shut down for six months or more prior to the expiration date of the current operation permit, shall be renewed for a period not to exceed five years from the date of shutdown, even if the emissions unit is not maintained in operational condition, provided:

(i) the owner or operator of the emissions unit demonstrates to the Department that the emissions unit may need to be reactivated and used, or that it is the owner's or operator's intent to apply to the Department for a permit to construct a new emissions unit at the facility before the end of the extension period; and

(ii) the owner or operator of the emissions unit agrees to and is legally prohibited from providing the allowable emission permitted by the renewed permit as an emissions offset to any other person under Rule 62-212.500, F.A.C.; and

(iii) the emissions unit was operating in compliance with all applicable rules as of the time the source was shut down.

c. Except as provided in Rule 62-210.300(2)(a)3.d., F.A.C., the operation permit for an emissions unit which has been shut down for five years or more prior to the expiration date of the current operation permit shall be renewed for a maximum period not to exceed ten years from the date of shutdown, even if the emissions unit is not maintained in operational condition, provided the conditions given in Rule 62-210.300(2)(a)3.b., F.A.C., are met and the owner or operator demonstrates to the Department that failure to renew the permit would constitute a hardship, which may include economic hardship.

d. The operation permit for an electric utility generating unit on cold standby or long-term reserve shutdown shall be renewed for a five-year period, and additional five-year periods, even if the unit is not maintained in operational condition, provided the conditions given in Rules 62-210.300(2)(a)3.b.(i) through (iii), F.A.C., are met.

4. In the case of an emissions unit permitted pursuant to Rules 62-210.300(2)(a)3.b., c., and d., F.A.C., include reasonable notification and compliance testing requirements for reactivation of such emissions unit and provide that the owner or operator demonstrate to the Department prior to reactivation that such reactivation would not constitute reconstruction pursuant to Rule 62-204.800(8), F.A.C.

[Rules 62-210.300(1) & (2), F.A.C.]

19. **Not federally enforceable. Notification of Startup.** The owners or operator of any emissions unit or facility which has a valid air operation permit which has been shut down more than one year, shall notify the Department in writing of the intent to start up such emissions unit or facility, a minimum of 60 days prior to the intended startup date.

(a) The notification shall include information as to the startup date, anticipated emission rates or pollutants released,



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changes to processes or control devices which will result in changes to emission rates, and any other conditions which may differ from the valid outstanding operation permit.

(b) If, due to an emergency, a startup date is not known 60 days prior thereto, the owner shall notify the Department as soon as possible after the date of such startup is ascertained.

[Rule 62-210.300(5), F.A.C.]

#### 20. Emissions Unit Reclassification.

(a) Any emissions unit whose operation permit has been revoked as provided for in Chapter 62-4, F.A.C., shall be deemed permanently shut down for purposes of Rule 62-212.500, F.A.C. Any emissions unit whose permit to operate has expired without timely renewal or transfer may be deemed permanently shut down, provided, however, that no such emissions unit shall be deemed permanently shut down if, within 20 days after receipt of written notice from the Department, the emissions unit owner or operator demonstrates that the permit expiration resulted from inadvertent failure to comply with the requirements of Rule 62-4.090, F.A.C., and that the owner or operator intends to continue the emissions unit in operation, and either submits an application for an air operation permit or complies with permit transfer requirements, if applicable.

(b) If the owner or operator of an emissions unit which is so permanently shut down, applies to the Department for a permit to reactivate or operate such emissions unit, the emissions unit will be reviewed and permitted as a new emissions unit.

[Rule 62-210.300(6), F.A.C.]

#### 21. Transfer of Air Permits.

(a) An air permit is transferable only after submission of an Application for Transfer of Air Permit (DEP Form 62-210.900(7)) and Department approval in accordance with Rule 62-4.120, F.A.C. For Title V permit transfers only, a complete application for transfer of air permit shall include the requirements of 40 CFR 70.7(d)(1)(iv), adopted and incorporated by reference at Rule 62-204.800, F.A.C. Within 30 days after approval of the transfer of permit, the Department shall update the permit by an administrative permit correction pursuant to Rule 62-210.360, F.A.C.

(b) For an air general permit, the provision of Rules 62-210.300(7)(a) and 62-4.120, F.A.C., do not apply. Thirty (30) days before using an air general permit, the new owner must submit an air general permit notification to the Department in accordance with Rule 62-210.300(4), F.A.C., or Rule 62-213.300(2)(b), F.A.C.

[Rule 62-210.300(7), F.A.C.]

#### 22. Public Notice and Comment.

##### (1) Public Notice of Proposed Agency Action.

(a) A notice of proposed agency action on permit application, where the proposed agency action is to issue the permit, shall be published by any applicant for:

1. An air construction permit;

2. An air operation permit, permit renewal or permit revision subject to Rule 62-210.300(2)(b), F.A.C., (i.e., a FESOP), except as provided in Rule 62-210.300(2)(b)1.b., F.A.C.; or

3. An air operation permit, permit renewal, or permit revision subject to Chapter 62-213, F.A.C., except Title V air general permits or those permit revisions meeting the requirements of Rule 62-213.412(1), F.A.C.

(b) The notice required by Rule 62-210.350(1)(a), F.A.C., shall be published in accordance with all otherwise applicable provisions of Rule 62-110.106, F.A.C. A public notice under Rule 62-210.350(1)(a)1., F.A.C., for an air construction permit may be combined with any required public notice under Rule 62-210.350(1)(a)2. or 3., F.A.C., for air operation permits. If such notices are combined, the public notice must comply with the requirements for both notices.

(c) Except as otherwise provided at Rules 62-210.350(2), (5), and (6), F.A.C., each notice of intent to issue an air construction permit shall provide a 14-day period for submittal of public comments.

##### (2) Additional Public Notice Requirements for Emissions Units Subject to Prevention of Significant Deterioration or Nonattainment - Area Preconstruction Review.

(a) Before taking final agency action on a construction permit application for any proposed new or modified facility or

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emissions unit subject to the preconstruction review requirements of Rule 62-212.400 or 62-212.500, F.A.C., the Department shall comply with all applicable provisions of Rule 62-110.106, F.A.C., and provide an opportunity for public comment which shall include as a minimum the following:

1. A complete file available for public inspection in at least one location in the district affected which includes the information submitted by the owner or operator, exclusive of confidential records under Section 403.111, F.S., and the Department's analysis of the effect of the proposed construction or modification on ambient air quality, including the Department's preliminary determination of whether the permit should be approved or disapproved;

2. A 30-day period for submittal of public comments; and

3. A notice, by advertisement in a newspaper of general circulation in the county affected, specifying the nature and location of the proposed facility or emissions unit, whether BACT or LAER has been determined, the degree of PSD increment consumption expected, if applicable, and the location of the information specified in paragraph 1. above; and notifying the public of the opportunity for submitting comments and requesting a public hearing.

(b) The notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall be prepared by the Department and published by the applicant in accordance with all applicable provisions of Rule 62-110.106, F.A.C., except that the applicant shall cause the notice to be published no later than thirty (30) days prior to final agency action.

(c) A copy of the notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall also be sent by the Department to the Regional Office of the U. S. Environmental Protection Agency and to all other state and local officials or agencies having cognizance over the location of such new or modified facility or emissions unit, including local air pollution control agencies, chief executives of city or county government, regional land use planning agencies, and any other state, Federal Land Manager, or Indian Governing Body whose lands may be affected by emissions from the new or modified facility or emissions unit.

(d) A copy of the notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall be displayed in the appropriate district, branch and local program offices.

(e) An opportunity for public hearing shall be provided in accordance with Chapter 120, F.S., and Rule 62-110.106, F.A.C.

(f) Any public comments received shall be made available for public inspection in the location where the information specified in Rule 62-210.350(2)(a)1., F.A.C., is available and shall be considered by the Department in making a final determination to approve or deny the permit.

(g) The final determination shall be made available for public inspection at the same location where the information specified in Rule 62-210.350(2)(a)1., F.A.C., was made available.

(h) For a proposed new or modified emissions unit which would be located within 100 kilometers of any Federal Class I area or whose emissions may affect any Federal Class I area, and which would be subject to the preconstruction review requirements of Rule 62-212.400 or 62-212.500, F.A.C.:

1. The Department shall mail or transmit to the Administrator a copy of the initial application for an air construction permit and notice of every action related to the consideration of the permit application.

2. The Department shall mail or transmit to the Federal Land Manager of each affected Class I area a copy of any written notice of intent to apply for an air construction permit; the initial application for an air construction permit, including all required analyses and demonstrations; any subsequently submitted information related to the application; the preliminary determination and notice of proposed agency action on the permit application; and any petition for an administrative hearing regarding the application or the Department's proposed action. Each such document shall be mailed or transmitted to the Federal Land Manager within fourteen (14) days after its receipt by the Department.

(3) Additional Public Notice Requirements for Facilities Subject to Operation Permits for Title V Sources.

(a) Before taking final agency action to issue a new, renewed, or revised air operation permit subject to Chapter 62-213, F.A.C., the Department shall comply with all applicable provisions of Rule 62-110.106, F.A.C., and provide an opportunity for public comment which shall include as a minimum the following:

1. A complete file available for public inspection in at least one location in the district affected which includes the

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information submitted by the owner or operator, exclusive of confidential records under Section 403.111, F.S.; and

2. A 30-day period for submittal of public comments.

(b) The notice provided for in Rule 62-210.350(3)(a), F.A.C., shall be prepared by the Department and published by the applicant in accordance with all applicable provisions of Rule 62-110.106, F.A.C., except that the applicant shall cause the notice to be published no later than thirty (30) days prior to final agency action. If written comments received during the 30-day comment period on a draft permit result in the Department's issuance of a revised draft permit in accordance with Rule 62-213.430(1), F.A.C., the Department shall require the applicant to publish another public notice in accordance with Rule 62-210.350(1)(a), F.A.C.

(c) The notice shall identify:

1. The facility;

2. The name and address of the office at which processing of the permit occurs;

3. The activity or activities involved in the permit action;

4. The emissions change involved in any permit revision;

5. The name, address, and telephone number of a Department representative from whom interested persons may obtain additional information, including copies of the permit draft, the application, and all relevant supporting materials, including any permit application, compliance plan, permit, monitoring report, and compliance statement required pursuant to Chapter 62-213, F.A.C. (except for information entitled to confidential treatment pursuant to Section 403.111, F.S.), and all other materials available to the Department that are relevant to the permit decision;

6. A brief description of the comment procedures required by Rule 62-210.350(3), F.A.C.;

7. The time and place of any hearing that may be held, including a statement of procedure to request a hearing (unless a hearing has already been scheduled); and

8. The procedures by which persons may petition the Administrator to object to the issuance of the proposed permit after expiration of the Administrator's 45-day review period.

[Rules 62-210.350(1) thru (3), F.A.C.]

#### 23. Administrative Permit Corrections.

(1) A facility owner shall notify the Department by letter of minor corrections to information contained in a permit. Such notifications shall include:

(a) Typographical errors noted in the permit;

(b) Name, address or phone number change from that in the permit;

(c) A change requiring more frequent monitoring or reporting by the permittee;

(d) A change in ownership or operational control of a facility, subject to the following provisions:

1. The Department determines that no other change in the permit is necessary;

2. The permittee and proposed new permittee have submitted an Application for Transfer of Air Permit, and the Department has approved the transfer pursuant to Rule 62-210.300(7), F.A.C.; and

3. The new permittee has notified the Department of the effective date of sale or legal transfer.

(e) Changes listed at 40 CFR 72.83(a)(1), (2), (6), (9) and (10), adopted and incorporated by reference at Rule 62-204.800, F.A.C., and changes made pursuant to Rules 62-214.340(1) and (2), F.A.C., to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o;

(f) Changes listed at 40 CFR 72.83(a)(11) and (12), adopted and incorporated by reference at Rule 62-204.800, F.A.C., to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o, provided the notification is accompanied by a copy of any EPA determination concerning the similarity of the change to those listed at Rule 62-210.360(1)(e), F.A.C.; and

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(g) Any other similar minor administrative change at the source.

(2) Upon receipt of any such notification, the Department shall within 60 days correct the permit and provide a corrected copy to the owner.

(3) After first notifying the owner, the Department shall correct any permit in which it discovers errors of the types listed at Rules 62-210.360(1)(a) and (b), F.A.C., and provide a corrected copy to the owner.

(4) For Title V source permits, other than general permits, a copy of the corrected permit shall be provided to EPA and any approved local air program in the county where the facility or any part of the facility is located.

[Rule 62-210.360, F.A.C.]

#### 24. Emissions Computation and Reporting.

(1) Applicability. This rule sets forth required methodologies to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with this rule. This rule is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.

(2) Computation of Emissions. For any of the purposes set forth in subsection 62-210.370(1), F.A.C., the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.

(a) Basic Approach. The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.

1. If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.

2. If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

3. If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

#### (b) Continuous Emissions Monitoring System (CEMS).

1. An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:

a. The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or

b. The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.

2. Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

a. A calibrated flowmeter that records data on a continuous basis, if available; or

b. The average flow rate of all valid stack tests conducted during a five-year period encompassing the period

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over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

3. The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

#### (c) Mass Balance Calculations.

1. An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:

a. Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and

b. Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.

2. Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

3. In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

#### (d) Emission Factors.

1. An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.

a. If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

b. Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.

c. The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

2. If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

(e) Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.

(f) Accounting for Emissions During Periods of Startup and Shutdown. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

(g) Fugitive Emissions. In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or

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emissions unit.

(h) Recordkeeping. The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

(3) Annual Operating Report for Air Pollutant Emitting Facility.

(a) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year.

(c) The annual operating report shall be submitted to the appropriate Department of Environmental Protection (DEP) division, district or DEP-approved local air pollution control program office by March 1 of the following year.

(d) Beginning with 2007 annual emissions, emissions shall be computed in accordance with the provisions of Rule 62-210.370(2), F.A.C., for purposes of the annual operating report.

[Rules 62-210.370(1), (2) and (3)(a), (c) & (d), F.A.C.]

25. Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.

[Rule 62-210.650, F.A.C.]

26. Forms and Instructions. The forms used by the Department in the stationary source control program are adopted and incorporated by reference in this section. The forms are listed by rule number, which is also the form number, with the subject, title and effective date. Copies of forms may be obtained by writing to the Department of Environmental Protection, Division of Air Resource Management, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, or by accessing the Division's website at [www.dep.state.fl.us/air](http://www.dep.state.fl.us/air). The requirement of Rule 62-4.050(2), F.A.C., to file application forms in quadruplicate is waived if an air permit application is submitted using the Department's electronic application form.

(1) Application for Air Permit - Long Form, Form and Instructions (Effective 02-02-2006).

(a) Acid Rain Part, Form and Instructions (Effective 06-16-2003).

1. Repowering Extension Plan, Form and Instructions (Effective 07/01/1995).
2. New Unit Exemption, Form and Instructions (Effective 04/16/2001).
3. Retired Unit Exemption, Form and Instructions (Effective 04/16/2001).
4. Phase II NOx Compliance Plan, Form and Instructions (Effective 01/06/1998).
5. Phase II NOx Averaging Plan, Form (Effective 01/06/1998).

(b) Reserved.

(5) Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions (Effective 02/11/1999).

(7) Application for Transfer of Air Permit – Title V Source, (Effective 04/16/2001).

[Rule 62-210.900, F.A.C.]

**Chapter 62-213, F.A.C.**

27. Responsible Official.

(1) Each Title V source must identify a responsible official on each application for Title V permit, permit revision, and permit renewal. For sources with only one responsible official, this is how the Title V source designates the responsible official.

(2) Each Title V source may designate more than one responsible official, provided a primary responsible official is designated as responsible for the certifications of all other designated responsible officials. Any action taken by the primary responsible official shall take precedence over any action taken by any other designated responsible official.

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(3) Any facility initially designating more than one responsible official or changing the list of responsible officials must submit a Responsible Official Notification Form (DEP Form No. 62-213.900(8)) designating all responsible officials for a Title V source, stating which responsible official is the primary responsible official, and providing an effective date for any changes to the list of responsible officials. Each individual listed on the Responsible Official Notification Form must meet the definition of responsible official given at Rule 62-210.200, F.A.C.

(4) A Title V source with only one responsible official shall submit DEP Form No. 62-213.900(8) for a change in responsible official.

(5) No person shall take any action as a responsible official at a Title V source unless designated a responsible official as required by this rule, except that the existing responsible official of any Title V source which has a change in responsible official during the term of the permit and before the effective date of this rule may continue to act as a responsible official until the first submittal of DEP Form No. 62-213.900(8) or the next application for Title V permit, permit revision or permit renewal, whichever comes first.

[Rules 62-213.202(1) thru (5), F.A.C.]

28. Annual Emissions Fee. Each Title V source permitted to operate in Florida must pay between January 15 and March 1 of each year, upon written notice from the Department, an annual emissions fee in an amount determined as set forth in Rule 62-213.205(1), F.A.C.

(1) (g) If the Department has not received the fee by February 15 of the year following the calendar year for which the fee is calculated, the Department will send the primary responsible official of the Title V source a written warning of the consequences for failing to pay the fee by March 1. If the fee is not postmarked by March 1 of the year due, the Department shall impose, in addition to the fee, a penalty of 50 percent of the amount of the fee unpaid plus interest on such amount computed in accordance with Section 220.807, F.S. If the Department determines that a submitted fee was inaccurately calculated, the Department shall either refund to the permittee any amount overpaid or notify the permittee of any amount underpaid. The Department shall not impose a penalty or interest on any amount underpaid, provided that the permittee has timely remitted payment of at least 90 percent of the amount determined to be due and remits full payment within 60 days after receipt of notice of the amount underpaid. The Department shall waive the collection of underpayment and shall not refund overpayment of the fee, if the amount is less than 1 percent of the fee due, up to \$50.00. The Department shall make every effort to provide a timely assessment of the adequacy of the submitted fee. Failure to pay timely any required annual emissions fee, penalty, or interest constitutes grounds for permit revocation pursuant to Rule 62-4.100, F.A.C.

(1) (i) Any documentation of actual hours of operation, actual material or heat input, actual production amount, or actual emissions used to calculate the annual emissions fee shall be retained by the owner for a minimum of five (5) years and shall be made available to the Department upon request.

(1) (j) A completed DEP Form 62-213.900(1), "Major Air Pollution Source Annual Emissions Fee Form", must be submitted by a responsible official with the annual emissions fee.

[Rules 62-213.205, (1)(g), (1)(i) & (1)(j), F.A.C.]

29. Reserved.

30. Reserved.

31. Air Operation Permit Fees. No permit application processing fee, renewal fee, modification fee or amendment fee is required for an operation permit for a Title V source.

[Rule 62-213.205(4), F.A.C.]

32. Permits and Permit Revisions Required. All Title V sources are subject to the permit requirements of Chapter 62-213, F.A.C., except those Title V sources permissible pursuant to Rule 62-213.300, F.A.C., Title V Air General Permits.

(1) No Title V source may operate except in compliance with Chapter 62-213, F.A.C.

(2) Except as provided in Rule 62-213.410, F.A.C., no source with a permit issued under the provisions of Chapter 62-213, F.A.C., shall make any changes in its operation without first applying for and receiving a permit revision if the change meets any of the following:

(a) Constitutes a modification;

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- (b) Violates any applicable requirement;
- (c) Exceeds the allowable emissions of any air pollutant from any unit within the source;
- (d) Contravenes any permit term or condition for monitoring, testing, recordkeeping, reporting or of a compliance certification requirement;
- (e) Requires a case-by-case determination of an emission limitation or other standard or a source specific determination of ambient impacts, or a visibility or increment analysis under the provisions of Chapter 62-212 or 62-296, F.A.C.;
- (f) Violates a permit term or condition which the source has assumed for which there is no corresponding underlying applicable requirement to which the source would otherwise be subject;
- (g) Results in the trading of emissions among units within a source except as specifically authorized pursuant to Rule 62-213.415, F.A.C.;
- (h) Results in the change of location of any relocatable facility identified as a Title V source pursuant to paragraph (a)-(e), (g) or (h) of the definition of "major source of air pollution" at Rule 62-210.200, F.A.C.;
- (i) Constitutes a change at an Acid Rain Source under the provisions of 40 CFR 72.81(a)(1), (2), or (3), (b)(1) or (b)(3), hereby incorporated by reference;
- (j) Constitutes a change in a repowering plan, nitrogen oxides averaging plan, or nitrogen oxides compliance deadline extension at an Acid Rain Source;

[Rules 62-213.400(1) & (2), F.A.C.]

33. Changes Without Permit Revision. Title V sources having a valid permit issued pursuant to Chapter 62-213, F.A.C., may make the following changes without permit revision, provided that sources shall maintain source logs or records to verify periods of operation:

- (1) Permitted sources may change among those alternative methods of operation;
- (2) A permitted source may implement operating changes, as defined in Rule 62-210.200, F.A.C., after the source submits any forms required by any applicable requirement and provides the Department and EPA with at least 7 days written notice prior to implementation. The source and the Department shall attach each notice to the relevant permit;
  - (a) The written notice shall include the date on which the change will occur, and a description of the change within the permitted source, the pollutants emitted and any change in emissions, and any term or condition becoming applicable or no longer applicable as a result of the change;
  - (b) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes;
- (3) Permitted sources may implement changes involving modes of operation only in accordance with Rule 62-213.415, F.A.C.

[Rule 62-213.410, F.A.C.]

34. Immediate Implementation Pending Revision Process.

- (1) Those permitted Title V sources making any change that constitutes a modification pursuant to the definition of modification at Rule 62-210.200, F.A.C., but which would not constitute a modification pursuant to 42 USC 7412(a) or to 40 CFR 52.01, 60.2, or 61.15, adopted and incorporated by reference at Rule 62-204.800, F.A.C., may implement such change prior to final issuance of a permit revision, provided the change:
  - (a) Does not violate any applicable requirement;
  - (b) Does not contravene any permit term or condition for monitoring, testing, recordkeeping or reporting, or any compliance certification requirement;
  - (c) Does not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination of ambient impacts, or a visibility or increment analysis under the provisions of Chapter 62-212 or 62-296, F.A.C.;



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(d) Does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and which the source has assumed to avoid an applicable requirement to which the source would otherwise be subject including any federally enforceable emissions cap or federally enforceable alternative emissions limit.

(2) A Title V source may immediately implement such changes after they have been incorporated into the terms and conditions of a new or revised construction permit issued pursuant to Chapter 62-212, F.A.C., and after the source provides to EPA, the Department, each affected state and any approved local air program having geographic jurisdiction over the source, a copy of the source's application for operation permit revision. The Title V source may conform its application for construction permit to include all information required by Rule 62-213.420, F.A.C., in lieu of submitting separate application forms.

(3) The Department shall process the application for operation permit revision in accordance with the provisions of Chapter 62-213, F.A.C., except that the Department shall issue a draft permit revision or a determination to deny the revision within 60 days of receipt of a complete application for operation permit revision or, if the Title V source has submitted a construction permit application conforming to the requirements of Rule 62-213.420, F.A.C., the Department shall issue a draft permit or a determination to deny the revision at the same time the Department issues its determination on issuance or denial of the construction permit application. The Department shall not take final action on the operation permit revision application until all the requirements of Rules 62-213.430(1)(a), (c), (d), and (e), F.A.C., have been complied with.

(4) Pending final action on the operation permit revision application, the source shall implement the changes in accordance with the terms and conditions of the source's new or revised construction permit. If any terms and conditions of the new or revised construction permit have not been complied with prior to the issuance of the draft operation permit revision, the operation permit shall include a compliance plan in accordance with the provisions of Rule 62-213.440(2), F.A.C.

(5) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes until after the Department takes final action to issue the operation permit revision.

(6) If the Department denies the source's application for operation permit revision, the source shall cease implementation of the proposed changes.

[Rule 62-213.412, F.A.C.]

#### 35. Permit Applications.

(1) Duty to Apply. For each Title V source, the owner or operator shall submit a timely and complete permit application in compliance with the requirements of Rules 62-213.420, F.A.C., and Rules 62-4.050(1) through (3), F.A.C.

##### (a) Timely Application.

3. For purposes of permit renewal, a timely application is one that is submitted in accordance with Rule 62-4.090, F.A.C.

##### (b) Complete Application.

1. Any applicant for a Title V permit, permit revision or permit renewal must submit an application on DEP Form No. 62-210.900(1), which must include all the information specified by Rule 62-213.420(3), F.A.C., except that an application for permit revision must contain only that information related to the proposed change(s) from the currently effective Title V permit and any other requirements that become applicable at the time of application. The applicant shall include information concerning fugitive emissions and stack emissions in the application. Each application for permit, permit revision or permit renewal shall be certified by a responsible official in accordance with Rule 62-213.420(4), F.A.C.

2. For those applicants submitting initial permit applications pursuant to Rule 62-213.420(1)(a)1., F.A.C., a complete application shall be an application that substantially addresses all the information required by the application form number 62-210.900(1), and such applications shall be deemed complete within sixty days of receipt of a signed and certified application unless the Department notifies the applicant of incompleteness within that time. For all other applicants, the applications shall be deemed complete sixty days after receipt, unless the Department, within sixty days after receipt of a signed application for permit, permit revision or permit renewal, requests additional documentation or information needed to process the application. An applicant making timely and complete application for permit, or timely application for permit renewal as described by Rule 62-4.090(1), F.A.C., shall continue to operate the source under the authority and provisions of any existing valid permit or Florida Electrical Power Plant Siting Certification, and in accordance with applicable

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requirements of the Acid Rain Program, until the conclusion of proceedings associated with its permit application or until the new permit becomes effective, whichever is later, provided the applicant complies with all the provisions of Rules 62-213.420(1)(b)3. and 4., F.A.C. Failure of the Department to request additional information within sixty days of receipt of a properly signed application shall not impair the Department's ability to request additional information pursuant to Rules 62-213.420(1)(b)3. and 4., F.A.C.

3. For those permit applications submitted pursuant to the provisions of Rule 62-213.420(1)(a)1., F.A.C., the Department shall notify the applicant if the Department becomes aware at any time during processing of the application that the application contains incorrect or incomplete information. The applicant shall submit the corrected or supplementary information to the Department within ninety days unless the applicant has requested and been granted additional time to submit the information. Failure of an applicant to submit corrected or supplementary information requested by the Department within ninety days or such additional time as requested and granted shall render the application incomplete.

4. For all applications other than those addressed at Rule 62-213.420(1)(b)3., F.A.C., should the Department become aware, during processing of any application that the application contains incorrect information, or should the Department become aware, as a result of comment from an affected State, an approved local air program, EPA, or the public that additional information is needed to evaluate the application, the Department shall notify the applicant within 30 days. When an applicant becomes aware that an application contains incorrect or incomplete information, the applicant shall submit the corrected or supplementary information to the Department. If the Department notifies an applicant that corrected or supplementary information is necessary to process the permit, and requests a response, the applicant shall provide the information to the Department within ninety days of the Department request unless the applicant has requested and been granted additional time to submit the information or, the applicant shall, within ninety days, submit a written request that the Department process the application without the information. Failure of an applicant to submit corrected or supplementary information requested by the Department within ninety days, or such additional time as requested and granted, or to demand in writing within ninety days that the application be processed without the information shall render the application incomplete. Nothing in this section shall limit any other remedies available to the Department.

[Rules 62-213.420(1)(a)3. and 62-213.420(1)(b)1., 2., 3. & 4., F.A.C.]

36. Confidential Information. Whenever an applicant submits information under a claim of confidentiality pursuant to Section 403.111, F.S., the applicant shall also submit a copy of all such information and claim directly to EPA. (also, see Condition No. 50.)

[Rule 62-213.420(2), F.A.C.]

37. Standard Application Form and Required Information. Applications shall be submitted under Chapter 62-213, F.A.C., on forms provided by the Department and adopted by reference in Rule 62-210.900(1), F.A.C. The information as described in Rule 62-210.900(1), F.A.C., shall be included for the Title V source and each emissions unit. An application must include information sufficient to determine all applicable requirements for the Title V source and each emissions unit and to evaluate a fee amount pursuant to Rule 62-213.205, F.A.C.

[Rule 62-213.420(3), F.A.C.]

38. a. Permit Renewal and Expiration. Permits being renewed are subject to the same requirements that apply to permit issuance at the time of application for renewal. Permit renewal applications shall contain that information identified in Rules 62-210.900(1) and 62-213.420(3), F.A.C. Unless a Title V source submits a timely application for permit renewal in accordance with the requirements of Rule 62-4.090(1), F.A.C., the existing permit shall expire and the source's right to operate shall terminate. No Title V permit will be issued for a new term except through the renewal process.

b. Permit Revision Procedures. Permit revisions shall meet all requirements of Chapter 62-213, F.A.C., including those for content of applications, public participation, review by approved local programs and affected states, and review by EPA, as they apply to permit issuance and permit renewal, except that permit revisions for those activities implemented pursuant to Rule 62-213.412, F.A.C., need not meet the requirements of Rule 62-213.430(1)(b), F.A.C. The Department shall require permit revision in accordance with the provisions of Rule 62-4.080, F.A.C., and 40 CFR 70.7(f), whenever any source becomes subject to any condition listed at 40 CFR 70.7(f)(1), hereby adopted and incorporated by reference. The below requirements from 40 CFR 70.7(f) are adopted and incorporated by reference in Rule 62-213.430(4), F.A.C.:

40 CFR 70.7(f): Reopening for Cause. (also, see Condition No. 4.)

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(1) This section contains provisions from 40 CFR 70.7(f) that specify the conditions under which a Title V permit shall be reopened prior to the expiration of the permit. A Title V permit shall be reopened and revised under any of the following circumstances:

(i) Additional applicable requirements under the Act become applicable to a major Part 70 source with a remaining permit term of 3 or more years. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 40 CFR 70.4(b)(10)(i) or (ii).

(ii) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approved by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit.

(iii) The permitting authority or EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

(iv) The Administrator or the permitting authority determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(2) Proceedings to reopen and issue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Such reopening shall be made as expeditiously as practicable.

(3) Reopenings under 40 CFR 70.7(f)(1) shall not be initiated before a notice of such intent is provided to the Part 70 source by the permitting authority at least 30 days in advance of the date that the permit is to be reopened, except that the permitting authority may provide a shorter time period in the case of an emergency.

[Rules 62-213.430(3) & (4), F.A.C.; and, 40 CFR 70.7(f)]

#### 39. Insignificant Emissions Units or Pollutant-Emitting Activities.

(a) All requests for determination of insignificant emissions units or activities made pursuant to Rule 62-213.420(3)(n), F.A.C., shall be processed in conjunction with the permit, permit renewal or permit revision application submitted pursuant to Chapter 62-213, F.A.C. Insignificant emissions units or activities shall be approved by the Department consistent with the provisions of Rule 62-4.040(1)(b), F.A.C. Emissions units or activities which are added to a Title V source after issuance of a permit under Chapter 62-213, F.A.C., shall be incorporated into the permit at its next renewal, provided such emissions units or activities have been exempted from the requirement to obtain an air construction permit and also qualify as insignificant pursuant to Rule 62-213.430(6), F.A.C.

(b) An emissions unit or activity shall be considered insignificant if all of the following criteria are met:

1. Such unit or activity would be subject to no unit-specific applicable requirement;

2. Such unit or activity, in combination with other units or activities proposed as insignificant, would not cause the facility to exceed any major source threshold(s) as defined in Rule 62-213.420(3)(c)1., F.A.C., unless it is acknowledged in the permit application that such units or activities would cause the facility to exceed such threshold(s);

3. Such unit or activity would not emit or have the potential to emit:

a. 500 pounds per year or more of lead and lead compounds expressed as lead;

b. 1,000 pounds per year or more of any hazardous air pollutant;

c. 2,500 pounds per year or more of total hazardous air pollutants; or

d. 5.0 tons per year or more of any other regulated pollutant.

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

40. Permit Duration. Permits for sources subject to the Federal Acid Rain Program shall be issued for terms of five years, provided that the initial Acid Rain Part may be issued for a term less than five years where necessary to coordinate the term of such part with the term of a Title V permit to be issued to the source. Operation permits for Title V sources may not be

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extended as provided in Rule 62-4.080(3), F.A.C., if such extension will result in a permit term greater than five years.

[Rule 62-213.440(1)(a), F.A.C.]

41. Monitoring Information. All records of monitoring information shall specify the date, place, and time of sampling or measurement and the operating conditions at the time of sampling or measurement, the date(s) analyses were performed, the company or entity that performed the analyses, the analytical techniques or methods used, and the results of such analyses.

[Rule 62-213.440(1)(b)2.a., F.A.C.]

42. Retention of Records. Retention of records of all monitoring data and support information shall be for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

[Rule 62-213.440(1)(b)2.b., F.A.C.]

43. Monitoring Reports. The permittee shall submit reports of any required monitoring at least every six (6) months. All instances of deviations from permit requirements must be clearly identified in such reports.

[Rule 62-213.440(1)(b)3.a., F.A.C.]

44. Deviation from Permit Requirements Reports. The permittee shall report in accordance with the requirements of Rules 62-210.700(6) and 62-4.130, F.A.C., deviations from permit requirements, including those attributable to upset conditions as defined in the permit. Reports shall include the probable cause of such deviations, and any corrective actions or preventive measures taken.

[Rule 62-213.440(1)(b)3.b., F.A.C.]

45. Reports. All reports shall be accompanied by a certification by a responsible official, pursuant to Rule 62-213.420(4), F.A.C.

[Rule 62-213.440(1)(b)3.c., F.A.C.]

46. If any portion of the final permit is invalidated, the remainder of the permit shall remain in effect.

[Rule 62-213.440(1)(d)1., F.A.C.]

47. It shall not be a defense for a permittee in an enforcement action that maintaining compliance with any permit condition would necessitate halting of or reduction of the source activity.

[Rule 62-213.440(1)(d)3., F.A.C.]

48. Any Title V source shall comply with all the terms and conditions of the existing permit until the Department has taken final action on any permit renewal or any requested permit revision, except as provided at Rule 62-213.412(2), F.A.C.

[Rule 62-213.440(1)(d)4., F.A.C.]

49. A situation arising from sudden and unforeseeable events beyond the control of the source which causes an exceedance of a technology-based emissions limitation because of unavoidable increases in emissions attributable to the situation and which requires immediate corrective action to restore normal operation, shall be an affirmative defense to an enforcement action in accordance with the provisions and requirements of 40 CFR 70.6(g)(2) and (3), hereby adopted and incorporated by reference.

[Rule 62-213.440(1)(d)5., F.A.C.]

50. Confidentiality Claims. Any permittee may claim confidentiality of any data or other information by complying with Rule 62-213.420(2), F.A.C. (also, see Condition No. 36.)

[Rule 62-213.440(1)(d)6., F.A.C.]

51. Statement of Compliance. (a)2. The permittee shall submit a Statement of Compliance with all terms and conditions of the permit that includes all the provisions of 40 CFR 70.6(c)(5)(iii), incorporated by reference at Rule 62-204.800, F.A.C., using DEP Form No. 62-213.900(7). Such statement shall be accompanied by a certification in accordance with Rule 62-213.420(4), F.A.C., for Title V requirements and with Rule 62-214.350, F.A.C., for Acid Rain requirements. Such

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statements shall be submitted (postmarked) to the Department and EPA:

a. Annually, within 60 days after the end of each calendar year during which the Title V permit was effective, or more frequently if specified by Rule 62-213.440(2), F.A.C., or by any other applicable requirement; and

b. Within 60 days after submittal of a written agreement for transfer of responsibility as required pursuant to 40 CFR 70.7(d)(1)(iv), adopted and incorporated by reference at Rule 62-204.800, F.A.C., or within 60 days after permanent shutdown of a facility permitted under Chapter 62-213, F.A.C.; provided that, in either such case, the reporting period shall be the portion of the calendar year the permit was effective up to the date of transfer of responsibility or permanent facility shutdown, as applicable.

3. In lieu of individually identifying all applicable requirements and specifying times of compliance with, non-compliance with, and deviation from each, the responsible official may use DEP Form No. 62-213.900(7) as such statement of compliance so long as the responsible official identifies all reportable deviations from and all instances of non-compliance with any applicable requirements and includes all information required by the federal regulation relating to each reportable deviation and instance of non-compliance.

(b) The responsible official may treat compliance with all other applicable requirements as a surrogate for compliance with Rule 62-296.320(2), Objectionable Odor Prohibited.

[Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

52. **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.]

53. **Forms and Instructions.** The forms used by the Department in the Title V source operation program are adopted and incorporated by reference in Rule 62-213.900, F.A.C. The form is listed by rule number, which is also the form number, and with the subject, title, and effective date. Copies of forms may be obtained by writing to the Department of Environmental Protection, Division of Air Resource Management, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, or by contacting the appropriate permitting authority.

(1) Major Air Pollution Source Annual Emissions Fee Form. (Effective 01/03/2001)

(7) Statement of Compliance Form. (Effective 06/02/2002)

(8) Responsible Official Notification Form. (Effective 06/02/2002)

[Rule 62-213.900, F.A.C.: Forms (1), (7) and (8)]

#### Chapter 62-256, F.A.C.

54. **Not federally enforceable. Open Burning.** This permit does not authorize any open burning nor does it constitute any waiver of the requirements of Chapter 62-256, F.A.C. Source shall comply with Chapter 62-256, F.A.C., for any open burning at the source.

[Chapter 62-256, F.A.C.]

#### Chapter 62-281, F.A.C.

55. **Refrigerant Requirements.** Any facility having refrigeration equipment, including air conditioning equipment, which uses a Class I or II substance (listed at 40 CFR 82, Subpart A, Appendices A and B), and any facility which maintains, services, or repairs motor vehicles using a Class I or Class II substance as refrigerant must comply with all requirements of 40 CFR 82, Subparts B and F, and with Rule 62-281.100, F.A.C. Those requirements include the following restrictions:

(1) Any facility having any refrigeration equipment normally containing 50 (fifty) pounds of refrigerant, or more, must keep servicing records documenting the date and type of all service and the quantity of any refrigerant added pursuant to 40 CFR 82.166;

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(2) No person repairing or servicing a motor vehicle may perform any service on a motor vehicle air conditioner (MVAC) involving the refrigerant for such air conditioner unless the person has been properly trained and certified as provided at 40 CFR 82.34 and 40 CFR 82.40, and properly uses equipment approved pursuant to 40 CFR 82.36 and 40 CFR 82.38, and complies with 40 CFR 82.42;

(3) No person may sell or distribute, or offer for sale or distribution, any substance listed as a Class I or Class II substance at 40 CFR 82, Subpart A, Appendices A and B, except in compliance with Rule 62-281.100, F.A.C., and 40 CFR 82.34(b), 40 CFR 82.42, and/or 40 CFR 82.166;

(4) No person maintaining, servicing, repairing, or disposing of appliances may knowingly vent or otherwise release into the atmosphere any Class I or Class II substance used as a refrigerant in such equipment and no other person may open appliances (except MVACs as defined at 40 CFR 82.152) for service, maintenance or repair unless the person has been properly trained and certified pursuant to 40 CFR 82.161 and unless the person uses equipment certified for that type of appliance pursuant to 40 CFR 82.158 and unless the person observes the practices set forth at 40 CFR 82.156 and 40 CFR 82.166;

(5) No person may dispose of appliances (except small appliances, as defined at 40 CFR 82.152) without using equipment certified for that type of appliance pursuant to 40 CFR 82.158 and without observing the practices set forth at 40 CFR 82.156 and 40 CFR 82.166;

(6) No person may recover refrigerant from small appliances, MVACs and MVAC-like appliances (as defined at 40 CFR 82.152), except in compliance with the requirements of 40 CFR 82, Subpart F.

[40 CFR 82; and, Chapter 62-281, F.A.C. (**Chapter 62-281, F.A.C., is not federally enforceable**)]

#### **Chapter 62-296, F.A.C.**

56. Industrial, Commercial, and Municipal Open Burning Prohibited. Open burning in connection with industrial, commercial, or municipal operations is prohibited, except when:

(a) Open burning is determined by the Department to be the only feasible method of operation and is authorized by an air permit issued pursuant to Chapter 62-210 or 62-213, F.A.C.; or

(b) An emergency exists which requires immediate action to protect human health and safety; or

(c) A county or municipality would use a portable air curtain incinerator to burn yard trash generated by a hurricane, tornado, fire or other disaster and the air curtain incinerator would otherwise be operated in accordance with the permitting exemption criteria of Rule 62-210.300(3), F.A.C.

[Rule 62-296.320(3), F.A.C.]

#### 57. Unconfined Emissions of Particulate Matter.

(4)(c)1. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction; alteration; demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions.

3. Reasonable precautions include the following:

a. Paving and maintenance of roads, parking areas and yards.

b. Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.

c. Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities.

d. Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent reentrainment, and from buildings or work areas to prevent particulate from becoming airborne.

e. Landscaping or planting of vegetation.

f. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.

**SECTION 5. APPENDIX V**

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g. Confining abrasive blasting where possible.

h. Enclosure or covering of conveyor systems.

4. In determining what constitutes reasonable precautions for a particular facility, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.

[Rules 62-296.320(4)(c)1., 3., & 4. F.A.C.]