Memorandum

Florida Department of Environmental Protection

TO: Joseph Kahn, Director

THRU: Trina Vielhauer TV
Jeff Koerner JK

FROM: Jonathan Holtom JH

DATE: November 5, 2007

SUBJECT: Final Construction Permit for Polk Power Partners, L.P.
Mulberry Cogeneration Facility
DEP File No. 1050217-006-AC / PSD-FL-187C

Attached for approval and signature is a Final construction permit for Polk Power Partner's Mulberry Cogeneration Facility. This permitting project is being processed at the applicant's request for a 6% increase in the heat input limit in order to take advantage of the increased firing temperature made available by a recent change in the turbine process control software. The applicant did not request an increase in any of the current permitted allowable short-term or annual emission rates for any existing emissions unit.

The Public Notice requirements were met on October 13, by publishing in The Polk County Democrat. No comments have been received from the public in response to this Public Notice, and no petitions were filed for an Administrative Hearing. The applicant did have one comment about the proper naming for the owner of the facility. As a result, all occurrences of the name Northern Star Generating were changed to Polk Power Partners, L.P. for the Mulberry Cogeneration Facility.

I recommend your approval and signature.

Attachments

/jh

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Allen Czerkiewicz, Plant Manager
Polk Power Partners, L.P.
P.O. Box 824
Bartow, FL 33831

DEP File No. 1050217-006-AC
PSD-FL-187C
Mulberry Cogeneration Facility
Polk County

Enclosed is Final Permit Number 1050217-006-AC / PSD-FL-217C. This permit authorizes a 6% increase in the heat input limit in order to take advantage of the increased firing temperature made available by a recent change in the turbine process control software. The applicant did not request an increase in any of the current permitted allowable short-term or annual emission rates for any existing emissions unit. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency Clerk hereby certifies that this Notice of Final Permit (including the Final Determination and the Final Permit) was sent by e-mail with return receipt requested before the close of business on 11/8/07 to the persons listed:

Mr. Allen Czerkiewicz, Plant Manager, Polk Power Partners, L.P. (allen.czerkiewicz@northernstargen.com)
Mr. Scott Osbourn, P.E., Golder Associates (sosbourn@golder.com)
Ms. Cindy Zhang-Torres, SWD (Cindy.Zhang-Torres@dep.state.fl.us)
Mr. Jim Little, EPA Region 4 (little.james@epa.gov)
Ms. Katy Forney, EPA Region 4 (forney.kathleen@epa.gov)

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) 11/8/07 (Date)

FINAL DETERMINATION

Polk Power Partners, L.P.
Mulberry Cogeneration Facility
DEP File No. 1050217-006-AC / PSD-FL-187C

The Department distributed a public notice package on October 4, 2007, to Polk Power Partner's Mulberry Cogeneration Facility. The permit was issued for a 6% increase in the heat input limit in order to take advantage of the increased firing temperature made available by a recent change in the turbine process control software. The applicant did not request an increase in any of the current permitted allowable short-term or annual emission rates for any existing emissions unit.

The facility is located at 3600 County Road 555, Bartow, Polk County.

COMMENTS/CHANGES

No comments were received by the Department from the public in response to the Draft permit and Public Notice. The applicant did have one comment about the proper naming for the owner of the facility. As a result, all occurrences of the name Northern Star Generating were changed to Polk Power Partners, L.P. for the Mulberry Cogeneration Facility.

CONCLUSION

The final action of the Department is to issue the final permit with the corrections noted above.

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:
Polk Power Partners, L.P.
Mulberry Cogeneration Facility
P.O. Box 824
Bartow, Florida 33831

ARMS Permit No.	1050217-006-AC / PSD-FL-187C
Facility ID No.	1050217
SIC No.	4911

Authorized Representative:
Allen Czerkiewicz, Plant Manager

PROJECT AND LOCATION

This permit increases the heat input limit by 6% to take advantage of the increased firing temperature made available by a recent change in the turbine process control software. The applicant is not requesting an increase in any of the current permitted allowable hourly or annual emission rates. This permit is a revision of the previous permitting actions and does not authorize any new construction.

The facility is located at 3600 County Road 555, Bartow, Polk County.

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.). The permittee is authorized to make changes in accordance with the conditions of this permit.

Joseph Kahn, Director
Division of Air Resource Management

FACILITY DESCRIPTION

The subject facility consists of a 126 megawatt (MW) combined-cycle cogeneration unit, which is comprised of one General Electric PG7111EA combustion turbine (CT), one heat recovery steam generator (HRSG) and one secondary boiler. The facility is fired with natural gas as the primary fuel and new No. 2 fuel oil as backup fuel. Emissions unit -001 is regulated under Acid Rain Phase II.

REGULATORY CLASSIFICATION

Title III: The facility is not a major source of hazardous air pollutants (HAP).

Title IV: The facility operates units subject to the acid rain provisions of the Clean Air Act.

Title V: The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The facility is a major stationary source pursuant to Rule 62-212.400, F.A.C. This project will not result in a significant emissions increase of any pollutant and is not subject to Prevention of Significant Deterioration (PSD) pre-construction review.

NSPS: The facility has units subject to New Source Performance Standards in 40 CFR 60.

NESHAP: The facility has no units subject to National Emissions Standards for HAP in 40 Code of Federal Regulations (CFR) 63.

RELEVANT DOCUMENTS

The documents listed form the basis of the permit. They are specifically related to this permitting action. These documents are on file with the Department.

- AC53-211670 / PSD-FL-187 issued 2-21-94;
- 1050217-003-AC / PSD-FL-187A issued 10-28-02;
- 1050217-004-AC / PSD-FL-187B issued 5-6-06;
- Construction permit application received 3-23-07;
- Request for additional information dated 4-20-07;
- Additional information response received 7-20-07; and
- Request to combine public notice with Title V renewal received 8-20-07.

The following condition replaces specific condition 5 of permit number 1050217-004-AC / PSD-FL-187B. Condition Nos. 6 and 7 are not changing; however, they are being included in this permit to indicate that the 10 year period of required monitoring and reporting, originally established in permit number 1050217-004-AC / PSD-FL-187B, restarts with the issuance of this permit.

5. Permitted Capacity. The CT shall be permitted to fire natural gas as the primary fuel and No. 2 fuel oil as a backup fuel for no more than 720 hours per year. Annual fuel consumption rates (based on operation at 20°F and hours of operation) shall not exceed those listed below:

Natural Gas			New No. 2 Fuel Oil		
MMBtu/hr (LHV)	MM ft^3/yr	Hours/Year	MMBtu/hr (LHV)	MM lbs/yr	Hours/Year
~~912~~ 970 [1]	8877.4 [2]	8760	~~912~~ 970 [3]	40.0 [4]	720

[1] Based on a lower heating value of natural gas of 950 Btu/cf and a gas usage rate of ~~960,250~~ 1,021,318 cf/hr at 59°F.
[2] Based on a lower heating value of natural gas of 950 Btu/cf and a gas usage rate of 1,013.4 Mcf/hr for 8760 hours per year at 20°F.
[3] Based on a lower heating value of fuel oil of 18,550 Btu/lb and an oil usage rate of ~~49,164~~ 52,290 lb/hr at 59°F.
[4] Based on a lower heating value of fuel oil of 18,550 Btu/lb and a fuel oil usage rate of 55,604 lb/hr for 720 hours per year at 20°F.

[BACT determination dated February 21, 1994; and, application 1050217-006-AC.]

6. Monitoring and Reporting Requirements.
   a. The permittee shall monitor the emissions of NO_X; and, using the most reliable information available, calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 10 years from the issuance date of this permit. Emissions shall be computed in accordance with Rule 62-210.370, F.A.C.
   b. The permittee shall report to the Department within 60 days after the end of each year during which records must be generated under subparagraph 62-212.300(1)(e)1., F.A.C., setting out the unit's annual emissions during the calendar year that preceded submission of the report. The report shall contain the following:
      1. The name, address and telephone number of the owner or operator of the major stationary source;
      2. The annual emissions as calculated pursuant to subparagraph 62-212.300(1)(e)1., F.A.C.;
      3. If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and,
      4. Any other information that the owner or operator wishes to include in the report.
   c. The information required to be documented and maintained pursuant to subparagraphs 62-212.300(1)(e)1. and 2., F.A.C., shall be submitted to the Department, which shall make it available for review to the general public.

[Rule 62-212.300(1)(e), F.A.C.]

7. Computation of Emissions.
   a. Because 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 continue to use such CEMS to compute NO_X emissions.
   b. 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:
      1. A calibrated flowmeter that records data on a continuous basis, if available; or

2. The average flow rate of all valid stack tests conducted during 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.

c. 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.

[Rule 62-210.370(2), F.A.C.]

The following conditions do not replace any other conditions of the above referenced existing permits. They are new conditions and requirements that are in addition to the existing ones.

8. Applicability of 40 CFR 60, Subpart KKKK. This emissions unit is subject to the terms and conditions contained in 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. Units subject to Subpart KKKK are exempt from regulation under 40 CFR 60, Subpart GG. In addition, this emissions unit is subject to the applicable NSPS General Provisions in Subpart A of 40 CFR 60.
[40 CFR 60, Subparts A and KKKK]

9. Sulfur Dioxide (SO_2). Pursuant to Subpart KKKK, SO_2 emissions from the combustion of any fuel shall not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. In order to ensure compliance with this limit:

a. As an acceptable alternative to the Custom Fuel Monitoring Schedule established in permit No. AC 53-211670 / PSD-FL-187, the maximum sulfur content of the natural gas may be monitored using the provisions of 40 CFR 75, Appendix D.

b. The maximum sulfur content of the new No. 2 fuel oil shall not exceed 0.05 percent, by weight.

[40 CFR 60.4330(a) and Application No. 1050217-006-AC]

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.

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 (Not Applicable);
    b. Determination of Prevention of Significant Deterioration (Not Applicable); and
    c. Compliance with New Source Performance Standards (Not Applicable).
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.

40 CFR 60, SUBPART KKKK – STANDARDS OF PERFORMANCE FOR STATIONARY COMBUSTION TURBINES

40 CFR 60, SUBPART KKKK – STANDARDS OF PERFORMANCE FOR STATIONARY COMBUSTION TURBINES

Table 1 to Subpart KKKK of Part 60-Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Sec. 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Sec. 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

Sec. 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in Sec. 60.4420(i), are exempt from the nitrogen oxides (NOX) emission limits in Sec. 60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NOX emission limits in Sec. 60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Sec. 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NOX) and sulfur dioxide (SO2).

Sec. 60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NOX specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NOX.

Sec. 60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

Sec. 60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

Sec. 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NOX emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. 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 related under this part.

Sec. 60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?

(a) If you are using water or steam injection to control NOX emissions, you must 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 when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NOX monitor and a diluent gas (oxygen (O2) or carbon dioxide (CO2)) monitor, to determine the hourly NOX emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

Sec. 60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NOX emissions, you must perform annual performance tests in accordance with Sec. 60.4400 to demonstrate continuous compliance. If the NOX emission result from the performance test is less than or equal to 75 percent of the NOX emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NOX emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in Sec. Sec. 60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NOX formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOX mode.

(iii) For any turbine that uses SCR to reduce NOX emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NOX emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in Sec. 75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in Sec. 75.19(c)(1)(iv)(H).

Sec. 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NOX CEMS is chosen:

(a) Each NOX diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NOX diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in Sec. 60.13(e)(2), during each full unit operating hour, both the NOX monitor and the diluent 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 with each monitor 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 for each monitor to validate the NOX emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

Sec. 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in Sec. 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in Sec. 60.4345(b), is obtained for both NOX and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOX emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O2 concentration exceeds 19.0 percent O2 (or the hourly average CO2 concentration is less than 1.0 percent CO2), a diluent cap value of 19.0 percent O2 or 1.0 percent CO2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NOX concentrations to 15 percent O2 is not allowed.

(d) If you have installed and certified a NOX diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under Sec. 60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NOX emission rates, in units of the emission standards under Sec. 60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad (Eq. 1)$$

Where:
E = hourly NOX emission rate, in lb/MWh,
(NOX)h = hourly NOX emission rate, in lb/MMBtu,
(HI)h = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, and
P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad (Eq. 2)$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.
(Pe)t = electrical or mechanical energy output of the combustion turbine in MW,
(Pe)c = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad \text{(Eq. 3)}$$

Where:
Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,
Q = measured steam flow rate in lb/h,
H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 106 = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL * AL} \quad \text{(Eq. 4)}$$

Where:
E = NOX emission rate in lb/MWh,
(NOX)m = NOX emission rate in lb/h,
BL = manufacturer's base load rating of turbine, in MW, and
AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in Sec. 60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in Sec. 60.4380(b)(1).

Sec. 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in Sec. Sec. 60.4335 and 60.4340 must be monitored during the performance test required under Sec. 60.8, to establish acceptable values and ranges. You 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. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NOX emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NOX emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in Sec. 75.19 or the NOX emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in Sec. 75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

Sec. 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in Sec. 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in Sec. 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see Sec. 60.17), which measure the major sulfur compounds, may be used.

Sec. 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for units located in continental areas and 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas or 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input for noncontinental areas. 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.

Sec. 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) 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).

(b) Gaseous fuel. If you elect not to demonstrate sulfur content using options in Sec. 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) Custom schedules. Notwithstanding the requirements of paragraph (b) 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 (c)(1) and (c)(2) 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. 60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) 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 (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, 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 greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) 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:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) 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 half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Sec. 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with Sec. 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with Sec. 60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

Sec. 60.4380 How are excess emissions and monitor downtime defined for NOX?

For the purpose of reports required under Sec. 60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling 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. 60.4320, 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 when a fuel is being burned that requires water or steam injection for NOX control will also be considered an excess emission.

(2) A period of monitor downtime is 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.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in Sec. Sec. 60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NOX emission rate exceeds the applicable emission limit in Sec. 60.4320. For the purposes of this subpart, a ``4-hour rolling average NOX emission rate" is the arithmetic average of the average NOX emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOX emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOX emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a ``30-day rolling average NOX emission rate" is the arithmetic average of all hourly NOX emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NOX emissions rates for the preceding 30 unit operating days if a valid NOX emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NOX concentration, CO2 or O2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NOX emission controls:

(1) An excess emission is 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.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

Sec. 60.4385 How are excess emissions and monitoring downtime defined for SO2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) 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 combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must 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 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) 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 ends on the date and hour of the next valid sample.

Sec. 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NOX limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NOX limit on a case-by-case basis as
determined by the Administrator. You must petition for the exemption.

Sec. 60.4395 When must I submit my reports?

All reports required under Sec. 60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Sec. 60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

(a) You must conduct an initial performance test, as required in Sec. 60.8. Subsequent NOX performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NOX concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NOX emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:
E = NOX emission rate, in lb/MWh
1.194×10^{-7} = conversion constant, in lb/dscf-ppm
(NOX)c = average NOX concentration for the run, in ppm
Qstd = stack gas volumetric flow rate, in dscf/hr
P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to Sec. 60.4350(f)(2); or

(ii) Measure the NOX and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NOX emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in Sec. 60.4350(f) to calculate the NOX emission rate in lb/MWh.

(2) Sampling traverse points for NOX and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must 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.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NOX and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NOX concentrations is within 10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than 5ppm or 0.5 percent CO2 (or O2) from the mean for all traverse points, then you may use three 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 three points must be located along the measurement line that exhibited the highest average NOX concentration during the stratification test; or

(B) For Turbines with a NOX standard greater than 15ppm @ 15%O2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOX concentrations is within 5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than 3ppm or 0.3 percent CO2 (or O2) from the mean for all traverse points; or

(C) For turbines with a NOX standard less than or equal located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOX concentrations is within 2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than 1ppm or 0.15 percent CO2 (or O2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NOX emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NOX with no additional post-combustion NOX control and you choose to monitor the steam or water to fuel ratio in accordance with Sec. 60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable Sec. 60.4320 NOX emission limit.

(4) Compliance with the applicable emission limit in Sec. 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NOX emission rate at each tested level meets the applicable emission limit in Sec. 60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in Sec. 60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 [deg]F during the performance test.

Sec. 60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?

If you elect to install and certify a NOX-diluent CEMS under Sec. 60.4345, then the initial performance test required under Sec. 60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 [deg]F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NOX emission limit under Sec. 60.4320 and to provide the required reference method data for the RATA of the CEMS described under Sec. 60.4335.

(d) Compliance with the applicable emission limit in Sec. 60.4320 is achieved if the arithmetic average of all of the NOX emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

Sec. 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NOX emission controls in accordance with Sec. 60.4340, the appropriate parameters must 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. 60.4355.

Sec. 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in Sec. 60.8. Subsequent SO2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see Sec. 60.17) for natural gas or ASTM D4177 (incorporated by reference, see Sec. 60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see Sec. 60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see Sec. 60.17).

(2) Measure the SO2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, ``Flue and Exhaust Gas Analyses,'' manual methods for sulfur dioxide (incorporated by reference, see Sec. 60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad \text{(Eq. 6)}$$

Where:
E = SO2 emission rate, in lb/MWh
1.664×10^{-7} = conversion constant, in lb/dscf-ppm
(SO2)c = average SO2 concentration for the run, in ppm
Qstd = stack gas volumetric flow rate, in dscf/hr
P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion

and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in
MW, calculated according to Sec. 60.4350(f)(2); or

(3) Measure the SO2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see Sec. 60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in Sec. 60.4350(f) to calculate the SO2 emission rate in lb/MWh.

(b) [Reserved]

Sec. 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

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.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion 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.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output--based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NOX emissions are higher than the applicable emission limit in Sec. 60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in Sec. 60.4330; 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.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

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. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 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.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit 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 unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

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.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

Table 1.--to Subpart KKKK of Part 60.--Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOX emission standard
New turbine firing natural gas, electric generating.	≤ 50 MMBtu/h	42 ppm at 15 percent O2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h	15 ppm at 15 percent O2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating.	≤ 50 MMBtu/h	96 ppm at 15 percent O2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive.	≤ 50 MMBtu/h	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 850 MMBtu/h	42 ppm at 15 percent O2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees	≤ 30 MW output	150 ppm at 15 percent O2 or 1,100 ng/J of

north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.		useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	> 30 MW output	96 ppm at 15 percent O2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine.	All sizes	54 ppm at 15 percent O2 or 110 ng/J of useful output (0.86 lb/MWh).

Harvey, Mary

From: Czerkiewicz, Allen [allen.czerkiewicz@northernstargen.com]

Sent: Friday, November 09, 2007 3:25 PM

To: Harvey, Mary

Subject: RE: Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C

It has been received...Thank You!

From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Friday, November 09, 2007 3:22 PM
To: Czerkiewicz, Allen
Subject: FW: Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C

Good Afternoon:
Please email me back if you have received this permit. I need the read receipt to complete the files.
Thanks,
Mary

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.

From: Harvey, Mary
Sent: Thursday, November 08, 2007 12:22 PM
To: 'Mr. Allen Czerkiewicz, Plant Manager, Polk Power Partners, L.P.'; 'Mr. Scott Osbourn, P.E., Golder Associates'; Zhang-Torres; 'Mr. Jim Little, EPA Region 4'; 'Ms. Katy Forney, EPA Region 4'
Cc: Holtom, Jonathan; Adams, Patty; Gibson, Victoria
Subject: Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site:
http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Harvey, Mary

From: Zhang-Torres
To: Harvey, Mary
Sent: Friday, November 09, 2007 8:23 AM
Subject: Read: Mulberry Cogeneration Facility - DEP File No. 1050217-006-AC/PSD-FL-187C

Your message

To:	'Mr. Allen Czerkiewicz, Plant Manager, Polk Power Partners, L.P.'; 'Mr. Scott Osbourn, P.E., Golder Associates'; Zhang-Torres; 'Mr. Jim Little, EPA Region 4'; 'Ms. Katy Forney, EPA Region 4'
Cc:	Holtom, Jonathan; Adams, Patty; Gibson, Victoria
Subject:	Mulberry Cogeneration Facility - DEP File No. 1050217-006-AC/PSD-FL-187C
Sent:	11/8/2007 12:22 PM

was read on 11/9/2007 8:22 AM.

Harvey, Mary

From: Harvey, Mary
Sent: Thursday, November 08, 2007 12:22 PM
To: 'Mr. Allen Czerkiewicz, Plant Manager, Polk Power Partners, L.P.'; 'Mr. Scott Osbourn, P.E., Golder Associates'; Zhang-Torres; 'Mr. Jim Little, EPA Region 4'; 'Ms. Katy Forney, EPA Region 4'
Cc: Holtom, Jonathan; Adams, Patty; Gibson, Victoria
Subject: Mulberry Cogeneration Facility - DEP File No. 1050217-006-AC/PSD-FL-187C
Attachments: MULBERRY COGENERATION FACILITY - DEP FILE #1050217-006-AC-FINAL.zip

Tracking:

Recipient	Read
'Mr. Allen Czerkiewicz, Plant Manager, Polk Power Partners, L.P.'	
'Mr. Scott Osbourn, P.E., Golder Associates'	
Zhang-Torres	Read: 11/9/2007 8:22 AM
'Mr. Jim Little, EPA Region 4'	
'Ms. Katy Forney, EPA Region 4'	
Holtom, Jonathan	Read: 11/8/2007 12:34 PM
Adams, Patty	Read: 11/8/2007 12:30 PM
Gibson, Victoria	Read: 11/8/2007 2:56 PM

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site:
http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Harvey, Mary

From:	Forney.Kathleen@epamail.epa.gov
Sent:	Thursday, November 08, 2007 1:25 PM
To:	Harvey, Mary
Cc:	Holtom, Jonathan
Subject:	Re: FW: Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C
Follow Up Flag:	Follow up
Flag Status:	Red

Thanks.

Katy R. Forney
Air Permits Section
EPA - Region 4
61 Forsyth St., SW
Atlanta, GA 30024

Phone: 404-562-9130
Fax: 404-562-9019

"Harvey, Mary" <Mary.Harvey@dep.state.fl.us>

11/08/2007 12:23 PM

To: Kathleen Forney/R4/USEPA/US@EPA

cc: "Holtom, Jonathan" <Jonathan.Holtom@dep.state.fl.us>

Subject: FW: Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C

From: Harvey, Mary
Sent: Thursday, November 08, 2007 12:22 PM
To: 'Mr. Allen Czerkiewicz, Plant Manager, Polk Power Partners, L.P.'; 'Mr. Scott Osbourn, P.E., Golder Associates'; Zhang-Torres; 'Mr. Jim Little, EPA Region 4'; 'Ms. Katy Forney, EPA Region 4'
Cc: Holtom, Jonathan; Adams, Patty; Gibson, Victoria
Subject: Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C

Dear Sir/Madam:

Harvey, Mary

From: Osbourn, Scott [Scott_Osbourn@golder.com]
To: Harvey, Mary
Sent: Thursday, November 08, 2007 12:43 PM
Subject: Read: Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C

Your message

To: Scott_Osbourn@golder.com
Subject:

was read on 11/8/2007 12:43 PM.

Harvey, Mary

From: Holtom, Jonathan
To: Harvey, Mary
Sent: Thursday, November 08, 2007 12:34 PM
Subject: Read: Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C

Your message

To:	'Mr. Allen Czerkiewicz, Plant Manager, Polk Power Partners, L.P.'; 'Mr. Scott Osbourn, P.E., Golder Associates'; Zhang-Torres; 'Mr. Jim Little, EPA Region 4'; 'Ms. Katy Forney, EPA Region 4'
Cc:	Holtom, Jonathan; Adams, Patty; Gibson, Victoria
Subject:	Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C
Sent:	11/8/2007 12:22 PM

was read on 11/8/2007 12:34 PM.

Harvey, Mary

From:	Adams, Patty
To:	Harvey, Mary
Sent:	Thursday, November 08, 2007 12:30 PM
Subject:	Read: Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C

Your message

To:	'Mr. Allen Czerkiewicz, Plant Manager, Polk Power Partners, L.P.'; 'Mr. Scott Osbourn, P.E., Golder Associates'; Zhang-Torres; 'Mr. Jim Little, EPA Region 4'; 'Ms. Katy Forney, EPA Region 4'
Cc:	Holtom, Jonathan; Adams, Patty; Gibson, Victoria
Subject:	Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C
Sent:	11/8/2007 12:22 PM

was read on 11/8/2007 12:30 PM.

Harvey, Mary

From: Gibson, Victoria
To: Harvey, Mary
Sent: Thursday, November 08, 2007 2:56 PM
Subject: Read: Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C

Your message

To:	'Mr. Allen Czerkiewicz, Plant Manager, Polk Power Partners, L.P.'; 'Mr. Scott Osbourn, P.E., Golder Associates'; Zhang-Torres; 'Mr. Jim Little, EPA Region 4'; 'Ms. Katy Forney, EPA Region 4'
Cc:	Holtom, Jonathan; Adams, Patty; Gibson, Victoria
Subject:	Mulberry Cogeneation Facility - DEP File No. 1050217-006-AC/PSD-FL-187C
Sent:	11/8/2007 12:22 PM

was read on 11/8/2007 2:56 PM.

NORTHERN STAR GENERATION

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JUL 20 2007

BUREAU OF AIR REGULATION

Polk Power Partners, L.P.
Mulberry Cogeneration Facility
3600 Highway 555
P.O. Box 824
Bartow, FL 33831

July19, 2007

Our Ref.: 073-9503

Florida Department of Environmental Protection
Bureau of Air Regulation
North Permitting Section
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attention: Mr. Jonathan Holtom, P.E.

RE: REQUEST FOR ADDITIONAL INFORMATION REGARDING HEAT INPUT REQUEST AT MULBERRY COGENERATION FACILITY
FILE NO.: 1050217-006-AC

Dear Mr. Holtom:

Mulberry Cogeneration has received the Department's request for additional information for the above-referenced permitting action. The responses to each comment are provided below, in the order in which they were presented in the Department's letter, dated April 20, 2007.

Comment 1. How many hours per 12 month period could the unit potentially be operated at the higher firing temperature?

Response Peak fire would typically be utilized during the summer season, characterized as May through September of each year. However, there also exists the possibility that high power demand may occur outside of that time period. Although peak firing mode is not proposed for continuous use, Mulberry Cogen has requested no restriction on the number of operating hours in this mode.

Comment 2. Is there a direct correlation between the heat input rate and the firing temperature for this unit?

Response There is a relationship between the heat input rate and the firing temperature. The more fuel that is combusted on a per unit basis, the higher the resulting firing temperature. The amount of fuel fired is automatically adjusted until the target turbine firing temperature is attained.

Comment 3. Is there a direct correlation between the firing temperature and the NO_x emissions concentration (ppm) and mass emissions rate (lb/hr) for this unit?

Response Yes, the increase in the firing temperature results in an increase in NOx on a concentration basis (i.e., ppmvd). Combined with a higher fuel firing rate, the NOx mass emissions (lb/hr) are also expected to proportionally increase. A summary table of the test firing results at the higher firing temperatures is included as Attachment 1 to this letter. The test summary indicates that, based on a comparison of base load to peak mode firing, actual NOx emissions increased about 27 percent on a concentration basis and about 31 percent on a mass emission rate basis.

Comment 4. Please provide the established heat input vs. NO_x emissions output curve for this unit over the past several years (i.e. before the recent 5% increase, after the 5% increase). If possible, please also provide a predicted curve for the heat input rate following the requested additional 6% increase in heat input.

Response There is no established heat input vs NOx emissions curve. However, the plant has established heat input curves that are a function of heat input and the inlet temperature to the turbine. The curves are provided as Attachment 2 to this letter for the three cases described above (i.e., original baseline, 5 percent increase to the baseline, and the currently requested peak firing case). In order to get a perspective on heat input vs corresponding NOx emissions values, please refer to the previously referenced Attachment 1 to this letter.

Comment 5. Please explain why you are requesting an increase in the allowable hourly NO_x mass emission rate from 52.7 lb/hour (which is based on the 15 ppm limit) to 58.8 lb/hour, but will be able to continue to operate within the permit limit of 15 ppmvd at all conditions.

Response The plant is not requesting an increase in the NOx concentration limit. However, at a NOx level of 15 ppmvd, combined with the higher firing temperature and heat input rate, the maximum mass emissions of NOx could increase to 58.8 lb/hr under certain operating conditions. However, based on the recent testing conducted during peak firing (response to comment 3 above); Mulberry is withdrawing the request for an increase in the allowable mass emission limit for NOx.

Comment 6. Based on the information contained in the application and a review of previous information, it appears that the unit routinely operates at about half of the allowable NO_x emissions concentration limit. Please explain how and why an additional 6% increase in heat input will create a need to increase the lb/hr emissions limit by almost 12% (52.7 lb/hr to 58.8 lb/hr).

Response Please note that a previous heat input increase was permitted (Final TV Permit No. 1050217-005-AV, issued August 3, 2006) to take advantage of the improved metallurgy of replacement hot gas path parts in the turbine. This increase in heat input from 869 MMBtu/hr (LHV, ISO) to 912 MMBtu/hr (LHV, ISO) was requested without a corresponding increase in the NOx mass emission limit because of the fact that the plant has historically operated well below it's permitted NOx emission limits. The approximate 12 percent increase in NOx mass emissions (lb/hour) was being requested is a means of 'truing up" the 15 ppmvd NOx limit and the requested heat input with the permitted lb/hour emission limit. However, as discussed above, Mulberry is withdrawing the request for a NOx emission increase.

The responses to the listed items above did not require new calculations or result in changes to previously submitted information; therefore, submission of new calculations, assumptions, reference material or revised pages of the application form were not necessary.

If you should have any questions, please contact Mr. Scott Osbourn, P.E., at (813) 287-1717.

Sincerely,

Allen Czerkiewicz
Plant Manager and Authorized Representative

Attachments

cc: Mr. Scott Osbourn, P.E., Golder Associates
Mr. Dave Kellermeyer, Northern Star Generation
Ms. Gwynne Johnson, Northern Star Generation
Ms. Mara Nasca, DEP, Southwest District Office
Mr. Greg Worley, U.S. EPA Region 4

SO/rlm

F/N: Response to FDEP Comments of 4.20.07.doc

ATTACHMENT 1

Peak Firing Test Report Summary

Peak Fire Testing Report
Polk Power Partners- Mulberry Cogeneration Facility
June 2007

Summary

Mulberry Cogeneration has completed a test of the plant's performance during Peak Fire mode, per the letter authorization signed by the Florida DEP dated May 21, 2007. Peak Fire mode increases the megawatt output by increasing the fuel input and resulting heat input with a corresponding increase in NOx concentration and NOx mass emission rates. The increase in NOx concentration was approximately 27% and the NOx mass emission rate increased 31% from the base load to Peak Fire mode. These rates are summarized in the table below. At all times during this testing the plant was in compliance with the current permit NOx limitations of 15 ppmdv @ 15% O2 and 52.7 lb/hr.

Megawatt output may also be increased by lowering the inlet temperature with chilled air and increasing mass flow rate through the unit. When the Peak Fire mode is coupled with the base load mode with chilled inlet air, similar increases in NOx concentration and NOx mass emission rates are seen.

Date	Inlet Temperature deg F	NOx ppm	NOx lb/hr	NOx lb/mmBTU
June 11, 2007 Base Load	91	7.4	24.92	0.0273
June 11, 2007 Peak Fire	88	9.37	32.63	0.0345
Percent Increase		**26.62%**	**30.94%**	**26.37%**
June 16, 2007 Base Load	88	7.37	25.06	0.0272
June 12, 2007 Peak Fire	89	9.07	31.35	0.0334
Percent Increase		**23.07%**	**25.10%**	**22.79%**
June 12, 2007 Base Load w/chiller	61	8.1	29.53	0.0298
June 12, 2007 Base Load w/chiller	67	7.7	27.68	0.0284
June 12, 2007 Peak Fire w/chiller	68	9.85	36.14	0.0363
Percent Increase		**27.92%**	**30.56%**	**27.82%**

The performance enhancement provided by the Peak Fire mode requires an increase in fuel input which results in an increased heat input, both of which are limited by the current permit. During the test periods the fuel input increase was variable from 1.28 to 3.56%, while the corresponding heat input increase, ISO corrected, was approximately 2.5 – 3.0%. This was expected since the fuel input will vary with weather conditions; specifically humidity and temperature. Results are summarized below.

Date	Inlet Temperature deg F	CT Gas Flow kscf/hr	ISO Corrected Heat Input LHV	MWs
June 11, 2007 Base Load	91	896.0	892.6	75.3
June 11, 2007 Peak Fire	88	927.9	**918.4**	78.4
Percent Increase		**3.56%**	**2.89%**	**4.12%**
June 16, 2007 Base Load	88	906.8	889.3	76.2
June 12, 2007 Peak Fire	89	918.4	**913.9**	78.1
Percent Increase		**1.28%**	**2.77%**	**2.49%**
June 12, 2007 Base Load w/chiller	61	970.3	909.0	84.1
June 12, 2007 Base Load w/chiller	67	955.1	906.6	82.4
June 12, 2007 Peak Fire w/chiller	68	979.5	**929.2**	84.4
Percent Increase		**2.55%**	**2.49%**	**2.43%**

Procedure

During the last maintenance outage in March 2007 the final components of the combustion turbine were upgraded to allow the unit to be fired at a higher (2080 deg F firing temperature) for relatively short periods of time to achieve a peak firing mode. The peak firing mode allows the unit to produce higher power output during periods of high electrical demand.

With the new components in place, the turbine controls were modified to increase the firing temperature and hence output with a single Operator command. During the recent testing of the unit the Operator initiated the Peak Fire mode signal and the unit immediately responded by calculating a new firing temperature based on the request for additional power. The transition period for the change from base load to Peak Fire is short, approximately 1 minute.

To complete a testing session the Operator once again gives the unit a single command and the operation is reversed; lowering the calculated firing temperature and hence load. Again the transition period is very short.

Conclusion

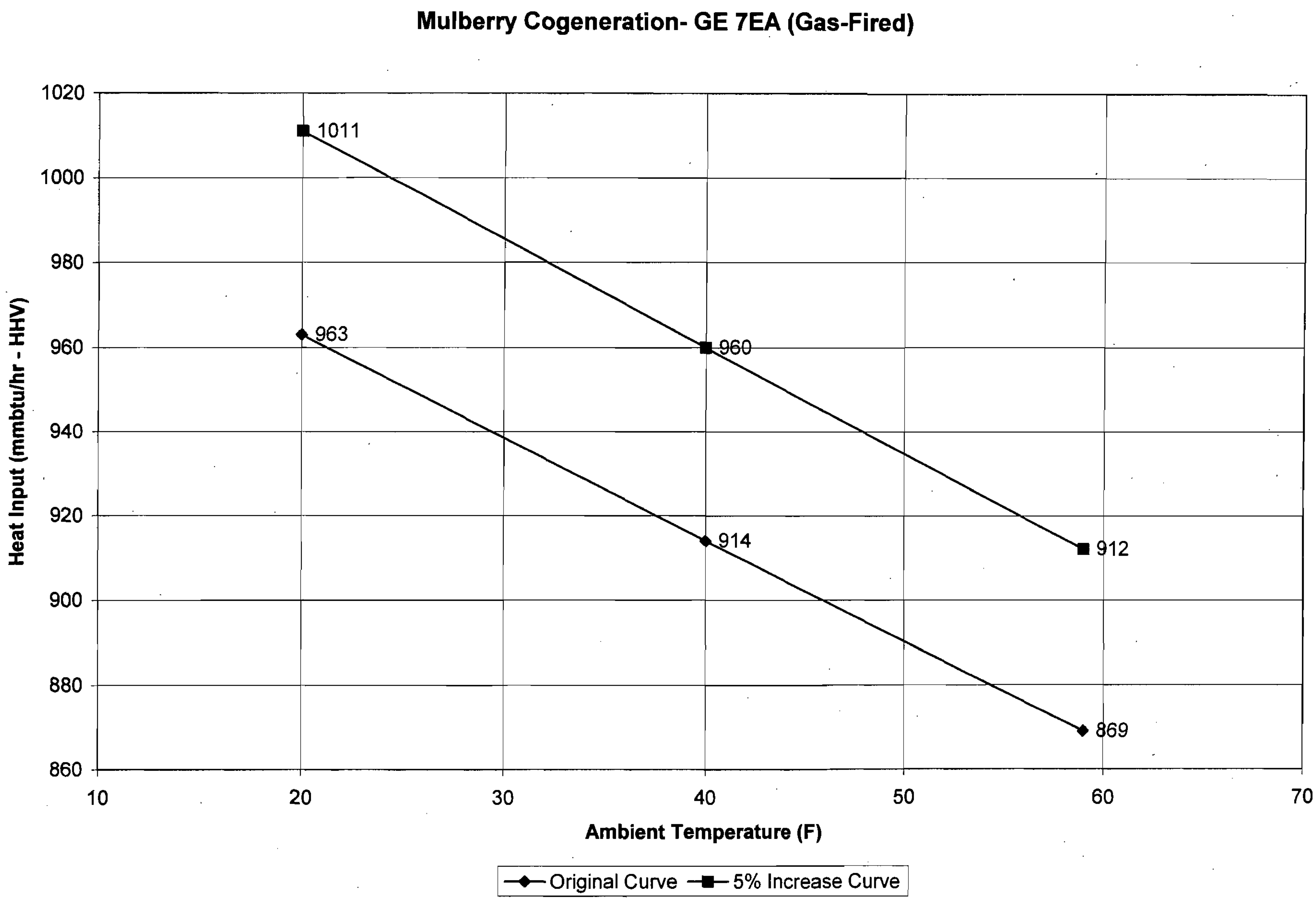
Peak Fire mode yields the desired effect of increasing power output for a relatively short period of time during high power demand periods. The increase in NOx concentration still allows the facility to operate below the current 15 ppm NOx concentration and 52.7 lb/hr NOx mass limits. The increase in fuel and heat input will require a modification to the current Title V permit.

Future Considerations

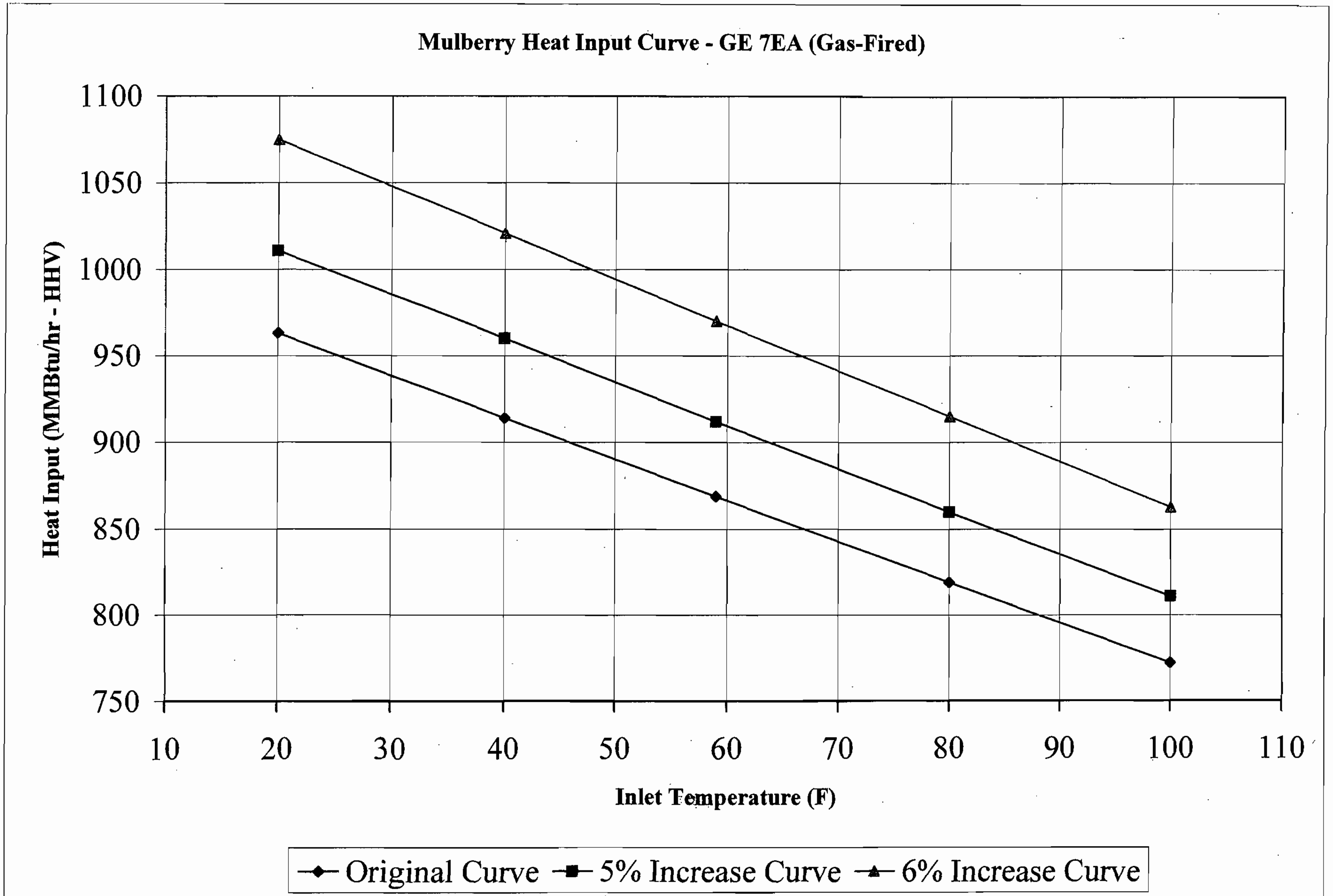
As you know we have been experiencing megawatt swings during shutdown that the OEM has been unable to tune out. The OEM recommends that we will have to perform additional tuning and this may have an impact on the NOx values in the table.

ATTACHMENT 2

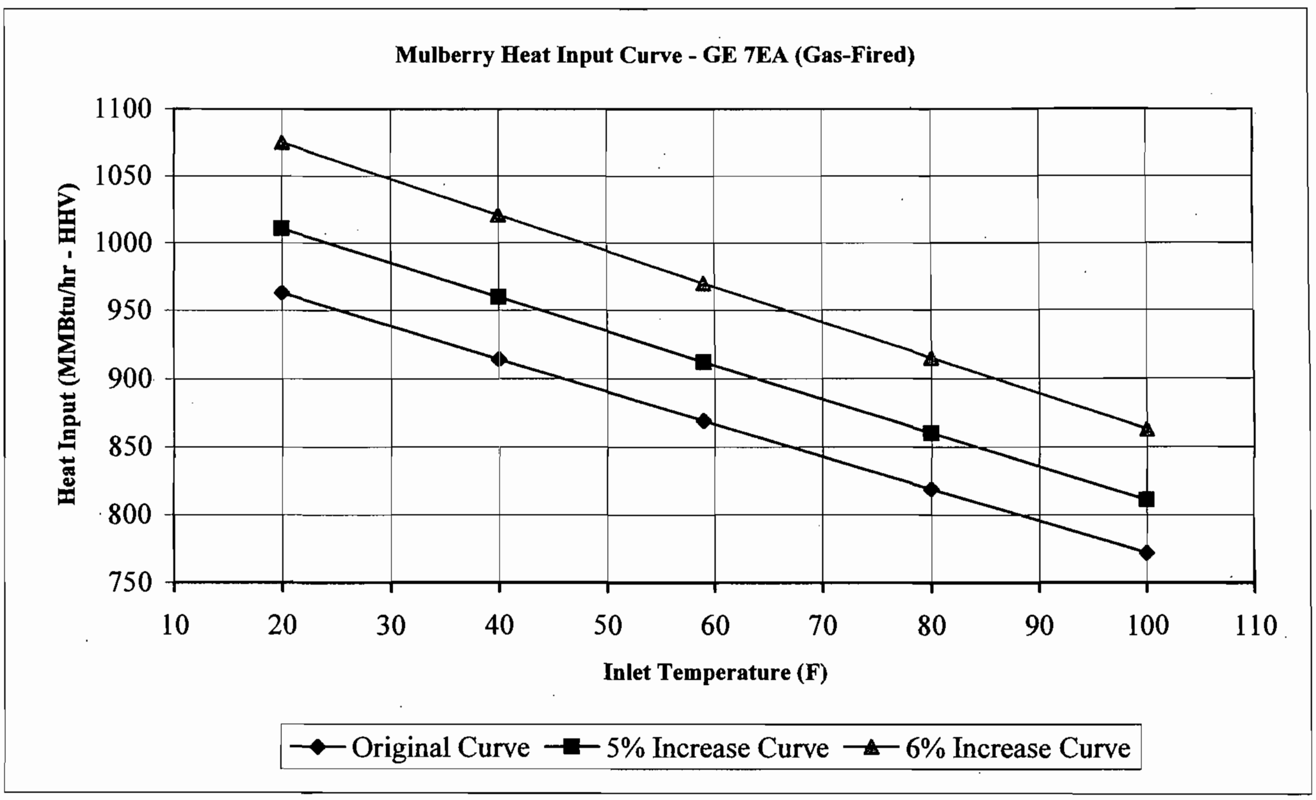
Mulberry Cogeneration Heat Input Curves



Mulberry Cogeneration- GE 7EA (Gas-Fired)
1020
1000
980
960
940
920
900
880
860
Heat Input (mmbtu/hr - HHV)
1011
960
912
963
914
869
10
20
30
40
50
60
70
Ambient Temperature (F)
Original Curve
5% Increase Curve


Mulberry Heat Input Curve - GE 7EA (Gas-Fired)
1100
1050
1000
950
900
850
800
750
Heat Input (MMBtu/hr - HHV)
10
20
30
40
50
60
70
80
90
100
110
Inlet Temperature (F)
Original Curve
5% Increase Curve
6% Increase Curve

	Heat Input (MMBtu/hr - HHV)		
Inlet Temp	Original Curve	5% Increase Curve	6% Increase Curve
20	963	1011	1075
40	914	960	1021
59	869	912	970
80	819	860	915
100	772	811	863



NORTHERN STAR
GENERATION

Polk Power Partners, L.P.
Mulberry Cogeneration Facility
3600 Highway 555
P.O. Box 824
Bartow, FL 33831

RECEIVED
MAR 23 2007
BUREAU OF AIR REGULATION

March 19, 2007

Mr. Al Linero, P.E.
Program Administrator, Permitting South Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Re: **Mulberry Cogeneration Facility (ID No 1050217)**
Application for Air Construction Permit – Heat Input Increase

Dear Mr. Linero:

This permit application for the Mulberry Cogeneration Facility serves to request an increase in the allowable fuel firing rate of the combustion turbine from 912 MMBTU/hr (LHV at ISO conditions) to 970 MMBTU/hr (LHV at ISO conditions), an increase of approximately six percent. The heat input increase requested in this application for a permit revision would allow firing temperatures to be further increased from 2,055°F to 2,080°F, during high power-demand periods. This application is in addition to the previous request for a heat input increase, that was subsequently incorporated into the revised TV permit (1050217-005-AV) issued on August 3, 2006. A project description is provided in the air application package (Attachment MC-FI-C2), as well as an emission evaluation (Attachment MC-FI-C3, Tables 1 through 6).

As the proposed project constitutes a modification under the provisions of 40 CFR Part 60 (i.e., a change in the method of operation accompanied by an increase in the actual hourly emission rate of a regulated pollutant) and will occur after February 18, 2005, the project will be subject to the newly promulgated Subpart KKKK. Therefore, this request will require a commitment from Mulberry to fire No. 2 fuel oil at a sulfur content no greater than 0.05 percent, versus the current allowable limit of 0.10 percent sulfur.

Accordingly, enclosed are an original and three copies of the air application package. If you should have any questions concerning this letter, please don't hesitate to contact Mr.

Scott Osbourn, P.E. at (813) 287-1717. Mulberry appreciates your consideration of this request. Thanks in advance for your timely processing of this permit revision request.

Sincerely,

Allen Czerkiewicz
Plant Manager and
Authorized Representative

Attachment

Cc: Dave Kellermeyer, Northern Star Generation
Scott Osbourn, P.E., Golder Associates Inc.

Department of
Environmental Protection
Division of Air Resource Management
APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for any air construction permit at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes to establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:
- An initial federally enforceable state air operation permit (FESOP); or
- An initial/revised/renewal Title V air operation permit.

Air Construction Permit & Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Polk Power Partners, L.P.**	
2. Site Name: **Mulberry Cogeneration Facility**	
3. Facility Identification Number: **1050217**	
4. Facility Location... Street Address or Other Locator: **3600 County Road 555** City: **Bartow** County: **Polk** Zip Code: **33831-0824**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Dave Kellermeyer, Vice President, EH&S**
2. Application Contact Mailing Address... Organization/Firm: **Northern Star Generation Services Company, LLC** Street Address: **2929 Allen Parkway, Suite 2200** City: **Houston** State: **TX** Zip Code: **77019**
3. Application Contact Telephone Numbers... Telephone: **(713) 580 - 6368** ext. Fax: **(713) 580 – 6320**
4. Application Contact Email Address: dave.kellermeyer@northernstargen.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

[x] Air construction permit.

[ ] Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

[ ] Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

[ ] Initial Title V air operation permit.

[ ] Title V air operation permit revision.

[ ] Title V air operation permit renewal.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

[ ] Air construction permit and Title V permit revision, incorporating the proposed project.

[ ] Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

[ ] I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

This permit application serves to request an increase in the allowable fuel firing rate of the combustion turbine (EU 001) from 912 MMBTU/hr (LHV at ISO conditions) to 970 MMBTU/hr (LHV at ISO conditions), an increase of approximately six percent. The heat input increase requested in this application for a permit revision would allow firing temperatures to be further increased from 2,055°F to 2,080°F, during high power-demand periods. This application is in addition to the previous request for a heat input increase, that was subsequently incorporated into the revised TV permit (1050217-005-AV) issued on August 3, 2006. A project description is provided in Attachment MC-FI-C2 and an emission evaluation in Attachment MC-FI-C3 (Tables 1 through 6).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	Combustion Turbine with HRSG	AC1B	

Application Processing Fee

Check one: ☐ Attached - Amount: $____________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name : **Allen Czerkiewicz, Plant Manager**			
2. Owner/Authorized Representative Mailing Address... Organization/Firm: **Mulberry Cogeneration Facility** Street Address: **3600 County Road 555**			
City: **Bartow**	State: **FL**	Zip Code: **33831-0824**	
3. Owner/Authorized Representative Telephone Numbers... Telephone:(863) 533-9073	ext. 235	Fax: (863) 533-4092	
4. Owner/Authorized Representative Email Address: allen.czerkiewicz@northernstargen.com			
5. Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.*			
Signature		3.19.07 Date	

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):

   ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.

   ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.

   ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.

   ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ext. Fax:

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   ________________________ ________________
   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Scott Osbourn, Senior Consultant**
   Registration Number: 57557
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates, Inc.***
   Street Address: **5100 Lemon Street, Suite 114**
   City: **Tampa** State: **FL** Zip Code: **33609**
3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287 - 1717** ext. **211** Fax: **(813) 287 – 1716**
4. Professional Engineer Email Address: sosbourn@golder.com
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here , if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Scott Osbourn
Signature

3/19/07
Date

(seal)

SCOTT OSBOURN LICENSE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

*** Board of Professional Engineers Certificate of Authorization No. 00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **413.6** North (km) **3080.6**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27/50/56** Longitude (DD/MM/SS) **81/52/39**	
3. Governmental Facility Code: **0** **(Not owned or operated by a Federal, State or Local Government)**	4. Facility Status Code:	5. Facility Major Group SIC Code: **(49) Electric, Gas and Sanitary Services**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Gwynne L. Johnson, Plant Engineer**
2. Facility Contact Mailing Address... Organization/Firm: **Mulberry Cogeneration Facility** Street Address: **3600 County Road 555** City: **Bartow** State: **FL** Zip Code: **33831-0824**
3. Facility Contact Telephone Numbers: Telephone: **(863) 533 - 9073** ext. Fax: **(863) 533 - 4092**
4. Facility Contact Email Address:

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name: **Allen Czerkiewicz, Plant Manager**
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: : **Mulberry Cogeneration Facility** Street Address: **3600 County Road 555** City: **Bartow** State: **FL** Zip Code: **33831-0824**
3. Facility Primary Responsible Official Telephone Numbers... Telephone: **(863) 533 -9073** ext. 235 Fax: **(863) 533-4092**
4. Facility Primary Responsible Official Email Address: allen.czerkiewicz@northernstargen.com

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. [x] Title V Source	
4. [x] Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. [x] One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. [x] Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: As the proposed project constitutes a modification under the provisions of 40 CFR Part 60 (i.e., a change in the method of operation accompanied by an increase in the actual hourly emission rate of a regulated pollutant) and will occur after February 18, 2005, the project will be subject to the newly promulgated Subpart KKKK. Therefore, the applicant will accept the applicable fuel oil sulfur limitation of 0.05 percent, versus the current allowable limit of 0.10 percent sulfur.	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
CO	**A**	
NO_x	**A**	
SO_2	**B**	

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: **05-JUL-02**
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: **05-JUL-02**
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: **05-JUL-02**

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☐ Attached, Document ID:__________ ☒ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **MC-FI-C2**
3. Rule Applicability Analysis: ☒ Attached, Document ID: **MC-FI-C3**
4. List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification: ☐ Attached, Document ID:__________ ☒ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications – N/A

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:________ ☐ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications – N/A

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:________ ☐ Not Applicable (revision application)	
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:________ ☐ Not Applicable (revision application with no change in applicable requirements)	
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:________ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.	
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:________ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable	
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:__________ ☐ Not Applicable	
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ ☐ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. **Skip this item if applying for an air construction permit or FESOP only.)**

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [x] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Combustion Turbine (CT) with HRSG (EU 001)

3. Emissions Unit Identification Number: **001**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A		**10-AUG-94**	**49**	[x] Yes ☐ No

9. Package Unit:
Manufacturer: **General Electric** Model Number: **PG7111 EA**

10. Generator Nameplate Rating: **82 MW**

11. Emissions Unit Comment:
No. 2 fuel oil is used as back-up fuel; limited to firing no more than 720 hours per year.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **NO_x emissions are controlled by dry low NO_x (DLN) combustors and water-injection** **28 – Steam or Water Injection – water-injection** **25 – Staged Combustion – Stage Combustion Technology – Dry Low NO_x Burners**
2. Control Device or Method Code(s): **28 and 25**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **970 million Btu/hr**		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Requested maximum heat input of 970 MMBtu/hr, based on lower heating value (LHV) at 59°F and 60 percent relative humidity (ISO conditions).**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:	2. Emission Point Type Code: **1 – A single emission point serving a single emission unit.**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **125 feet**	7. Exit Diameter: **15 feet**
8. Exit Temperature: **220 °F**	9. Actual Volumetric Flow Rate: **679,324 acfm**	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: Dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **413.6** North (km): **3080.6**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **27/50/56** Longitude (DD/MM/SS) **81/53/11**

15. Emission Point Comment:

Emission point calculations assume base load conditions at 59°F for natural gas firing.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **2**

1. Segment Description (Process/Fuel Type): **Internal Combustion Engine; Electric Generation; Distillate Oil; Turbine**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 Gallons Distillate Oil (Diesel Burned)**	
4. Maximum Hourly Rate: **8.2**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: 132
10. Segment Comment: **Max hourly rate based on 20°F inlet temperature (1,082 MMBtu/hr at fuel LHV presented above). Permit condition (Specific Condition A.2) limits annual fuel oil usage to no more than 40.0 MM lb/yr and 720 hours per year of operation. Note—Subpart KKKK limits fuel oil sulfur content to 0.05 percent.**		

Segment Description and Rate: Segment **2** of **2**

1. Segment Description (Process/Fuel Type): **Internal Combustion Engine; Electric Generation; Distillate Oil; Turbine**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Natural Gas Burned**	
4. Maximum Hourly Rate: **1.13**	5. Maximum Annual Rate: **8,877.4**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **946**
10. Segment Comment: **Max hourly rate based on 20°F inlet temperature (1,067 MMBtu/hr at fuel LHV presented above). Permit condition (Specific Condition A.2) limits annual natural gas usage to no more than 8,877.4 MM cf/yr. Max allowable sulfur content equals 1 gr/100 scf.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			**EL**
NO_x	**Low NO_x Burners**	**Water Injection**	**EL**
SO_2			**EL**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions
Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO - Carbon Monoxide**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **75.3** lb/hour **232** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **48.1** tons/year	8.b. Baseline 24-month Period: From: **1/1/04** To: **12/31/05**
9.a. Projected Actual Emissions (if required): **53.4** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential hourly emissions are based on fuel oil firing at ISO conditions. Potential annual emissions are based on natural gas firing at ISO conditions for 8,760 hr/yr.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **75.3** lb/hour	4. Equivalent Allowable Emissions: **75.3** lb/hour **27.1** tons/year
5. Method of Compliance: **EPA Reference Method 10 testing.**	
6. Allowable Emissions Comment (Description of Operating Method): **While firing fuel oil. Basis for allowable: AC 53-211670 and BACT determination dated February 21, 1994.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **25 ppmdv @ 15% O_2**	4. Equivalent Allowable Emissions: **53.0 lb/hour** **232 tons/year**
5. Method of Compliance: **EPA Reference Method 10 testing.**	
6. Allowable Emissions Comment (Description of Operating Method): **While firing natural gas. Basis for allowable: AC 53-211670 and BACT determination dated February 21, 1994.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x – Nitrogen Oxides**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **164** lb/hour **230.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **42 ppmvd @ 15% O_2** Reference:	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **49.1** tons/year	8.b. Baseline 24-month Period: From: **1/1/05** To: **12/31/06**
9.a. Projected Actual Emissions (if required): **55.6** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential hourly emissions are based on fuel oil firing at ISO conditions. Potential annual emissions are based on natural gas firing at ISO conditions for 8,760 hr/yr.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1 of 2**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **42 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **164** lb/hour **59** tons/year
5. Method of Compliance: **EPA Reference Method 20 or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 4-hour rolling average as measured by the NO_x CEMS while firing fuel oil, excluding periods of startup and shutdown. Basis for allowable: AC 53-211670 and BACT determination dated February 21, 1994; and 1050217-004-AC.**	

Allowable Emissions Allowable Emissions **2 of 2**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **15 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **58.8** lb/hour **230.7** tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 4-hour rolling average as measured by the NO_x CEMS while firing natural gas, excluding periods of startup and shutdown. Basis for allowable: AC 53-211670 and BACT determination dated February 21, 1994; and 1050217-004-AC.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2 – Sulfur Dioxide**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **416.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): **1.7** Tons/year	8.b. Baseline 24-month Period: From: **1/1/02** To: **12/31/03**
9.a. Projected Actual Emissions (if required): **1.9** Tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 percent in fuel oil**	4. Equivalent Allowable Emissions:
5. Method of Compliance: **Fuel analysis for sulfur content, each fuel oil delivery.**	
6. Allowable Emissions Comment (Description of Operating Method): **While firing No. 2 fuel oil. Basis for allowable: AC 53-211670 and BACT determination dated February 21, 1994. Note- NSPS, Subpart KKKK limits fuel oil sulfur content to 0.05 percent.**	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: Lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1 of 2**

1. Visible Emissions Subtype: **VE 10 – Visible Emission – 10% Opacity**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10%** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **While firing natural gas. Permit AC 53-211670.**	

Visible Emissions Limitation: Visible Emissions Limitation **2 of 2**

1. Visible Emissions Subtype: **VE 20 – Visible Emission – 20% Opacity**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20%** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **While firing fuel oil. Permit AC 53-211670.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **EM - Emission**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **ACME** Model Number: **951C**	Serial Number: **1000195**
5. Installation Date:	6. Performance Specification Test Date: **27-DEC-95**
7. Continuous Monitor Comment: **Status is inactive.**	

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **EM - Emission**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: **ROSEMOUNT** Model Number: **951C**	Serial Number: **1000195**
5. Installation Date: **18-DEC-95**	6. Performance Specification Test Date: **27-DEC-95**
7. Continuous Monitor Comment: **System installed in accordance with AC Permit, AC 53-211670. Status is active.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **3** of **5**

1. Parameter Code: **O_2 – Oxygen**	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: **SERVOMEX** Model Number: **1400 B**	Serial Number: **1420B/697**
5. Installation Date: **18-DEC-95**	6. Performance Specification Test Date: **27-DEC-95**
7. Continuous Monitor Comment: **System installed in accordance with AC Permit, AC 53-211670. Status is active.**	

Continuous Monitoring System: Continuous Monitor **4** of **5**

1. Parameter Code: **O_2 – Oxygen**	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: **ANARAD** Model Number: **AR-22**	Serial Number:
5. Installation Date: **11-NOV-94**	6. Performance Specification Test Date: **21-FEB-95**
7. Continuous Monitor Comment: **System installed in accordance with AC Permit, AC 53-211670. Status is inactive.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **5 of 5**

1. Parameter Code: **EM - Emission**	2. Pollutant(s): **NOx**
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: **ANARAD** Model Number: **AR-880**	Serial Number: **1234**
5. Installation Date: **11-NOV-94**	6. Performance Specification Test Date: **21-FEB-95**
7. Continuous Monitor Comment: **Emission is NOx. Status is inactive.**	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ____ [x] Previously Submitted, Date **05-JUL-02**

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ____ [x] Previously Submitted, Date **05-JUL-02**

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ____ [x] Previously Submitted, Date **05-JUL-02**

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ____ [x] Previously Submitted, Date **05-JUL-02**
☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ____ [x] Previously Submitted, Date **05-JUL-02**
☐ Not Applicable

6. Compliance Demonstration Reports/Records
☐ Attached, Document ID: ____
Test Date(s)/Pollutant(s) Tested: ____

☐ Previously Submitted, Date: ____
Test Date(s)/Pollutant(s) Tested: ____

[x] To be Submitted, Date (if known): 4/9/07
Test Date(s)/Pollutant(s) Tested: 2/22/07 for NOx, CO and VE

☐ Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
☐ Attached, Document ID: ____ [x] Not Applicable

Additional Requirements for Air Construction Permit Applications –N/A

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID: ___________ ☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: ___________ ☐ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: ___________ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications –N/A

1. Identification of Applicable Requirements
   ☐ Attached, Document ID: ___________
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: ___________ ☐ Not Applicable
3. Alternative Methods of Operation
   ☐ Attached, Document ID: ___________ ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: ___________ ☐ Not Applicable
5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID:_
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:__________
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:__________
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:__________
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:__________
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:__________
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:__________
   ☐ Not Applicable

Additional Requirements Comment

ATTACHMENT MC-FI-C2

Project Description

ATTACHMENT MC-FI-C2

Mulberry Cogeneration Facility

Heat Input Increase Request
Project Description

Mulberry Cogeneration Facility is seeking an increase in the allowable fuel firing rate of the General Electric PG7111EA combustion turbine (Emission Unit EU 001) from 912 MMBtu/hr (LHV, corrected to ISO conditions) to 970 MMBtu/hr (LHV, corrected to ISO conditions). In addition, Mulberry seeks an increase in the hourly NOx mass emission rate from 52.7 lb/hour to 58.8 lb/hour. No increase in the emission limits of any other pollutant is being requested, nor is an increase in the annual allowable NOx emissions being sought.

The purpose of this request is to be able to increase turbine firing temperature in order to increase plant output during periods of peak electricity demand. This increased firing temperature capability was established as a result of the previous normal replacement of hot gas section parts with functionally identical parts of a different metallurgy. That equipment replacement was addressed in a previous permit application for a heat input increase, submitted on September 14, 2005 (current Final TV Permit No. 1050217-005-AV, issued August 3, 2006). That previous permit modification allowed the increase of maximum firing temperature from 2020 °F to 2055 °F, which produced an estimated increase in peak firing rates from 869 MMBtu/hr to 912 MMBtu/hr (both LHV, adjusted to ISO conditions). The heat input increase requested in this permit revision application would allow firing temperatures to be further increased from 2,055 °F to 2,080 °F, during high power demand periods.

There are no physical modifications to the gas turbine required to implement this higher firing rate. The scope of the modification is limited to changes in the turbine process control software. To obtain an increase in fuel flow (peak load), the operating schedule (exhaust temperature control curve) in the control system would be modified to reflect the necessary changes. Subsequent to the software change, turbine tuning would be conducted at the peak firing temperatures.

When Mulberry previously applied for a heat input increase of approximately 5 percent, this additional capacity currently being sought through reprogramming of the control software was not considered due to excessive maintenance associated with the higher firing temperatures. An increase in firing temperature, for a given configuration, will increase thermal stresses and the frequency of inspection intervals for the combustion system and hot gas path, based on the hours at "higher firing temperature" (peak load) operation. However, given the relatively modest increase in firing temperature associated with the requested heat input increase, Mulberry has concluded that these potential heat stress impacts and their associated maintenance costs would be minimal. This conclusion is supported by the fact that implementation of the higher firing temperatures is expected to occur relatively infrequently.

Tables 1 through 6 of this attachment present the emissions evaluation associated with this request. As stated previously, peak firing of the gas turbine at 2,080 °F is expected to increase the maximum heat input on gas-firing by about 6 percent compared to firing at 2,055 °F. Table 1 presents the current potential to emit and emission limits (EU 001) based on permit conditions. Table 2 summarizes past actual emissions data for the facility, from 2001 through 2006. Table 3 summarizes the highest past actual 2-year average value per pollutant (TPY) for the facility. Recent revisions to the State of Florida's new source review program (62-210.200) now require that "actual emissions" be determined over "consecutive 24-month periods", rather than the highest 2 year period in the previous 5 years. Therefore, Table 3 also indicates which 24-month periods were considered for each pollutant. Table 4 provides an estimate of the annual emissions increase associated with this requested higher firing temperature. The estimated increases associated with Mulberry's previous request for a heat input increase are presented in Table 5. Finally, Table 6 presents the net effect of the referenced requests for heat input increases (i.e., the previous 5 percent increase request and the current request for a 6 percent increase).

Emissions during peak firing will not exceed the SERs that would trigger PSD review for affected pollutants and emissions will continue to be comfortably within all of the facility's permitted emission limits. This request will trigger applicability of the recently promulgated NSPS, Subpart KKKK. This is due to the fact that this request constitutes a change in the method of operation accompanied by an increase in the "actual" hourly emission rate of a regulated pollutant, commencing after February 18, 2005. The facility, as currently permitted, will meet the allowable emissions requirements in this newly promulgated NSPS.

To reiterate, Mulberry is requesting an increase in the allowable heat input limit and the hourly NOx emission limit. The plant will continue to operate within the permit limit of 15 ppmvd @ 15% O_2 under all conditions. It is anticipated that the peak firing capability will be used infrequently, and primarily during the summer months. However, for the purposes of this permit modification, Mulberry is seeking the ability to implement peak firing without any restrictions on the annual hours of use of this operating scenario.

ATTACHMENT MC-FI-C3

Emissions Evaluation

TABLE 1
Mulberry Cogeneration Facility
Current Permit Limits

Pollutant ID	EU 001 CT/HSRG				Total
	Emissions Current Potential		Emissions Current Potential	Reference Note	Emissions (EU 001) Current Potential
	lb/hr	ppmvd @ 15% O_2	TPY		TPY
NOx (gas)	52.7	15	230.7	A.5.1 [1]	289.7
NOx (oil)	164	42	59	A.5.2 [1]	
SO2	---	---	416.5	A.7 [1,2]	416.5
CO (gas)	53	25	232	A.9 [1]	259.1
CO (oil)	75.3	---	27.1	A.10 [1]	

[1]TV Permit No. 1050217-005-AV, Condition Number

[2]Maximum sulfur content shall not exceed 0.10%, by weight

TABLE 2

Mulberry Cogeneration Facility - Historical Annual Emissions by Unit

Year		2001			2002			2003		
Pollutant		EU 001 CT/HSRG (tpy)	EU 002 Secondary Boiler (tpy)	*Total (tpy)*	EU 001 CT/HSRG (tpy)	EU 002 Secondary Boiler (tpy)	*Total (tpy)*	EU 001 CT/HSRG (tpy)	EU 002 Secondary Boiler (tpy)	*Total (tpy)*
Volatile Organic Compounds	VOC	23.0	0.0008	*23.0*	20.4	0.00066	*20.4*	23.5	0.0001	*23.5*
Sulfur Dioxide	SO_2	1.7	0.0006	*1.7*	1.5	0.00045	*1.5*	1.8	0.00002	*1.8*
Particulate Matter	PM	25.6	0.008	*25.6*	22.7	0.0064	*22.7*	26.1	0.0009	*26.1*
Nitrogen Oxides	NO_x	62.5	0.051	*62.6*	46.5	0.14	*46.6*	46.6	0.033	*46.6*
Carbon Monoxide	CO	6.8	0.0	*6.8*	26.2	0.0	*26.2*	8.3	0.0	*8.3*
Particulate Matter 10	PM_{10}	12.3	0.0018	*12.3*	10.9	0.0014	*10.9*	12.5	0.0002	*12.5*

Source: AOR Data

TABLE 2 (continued)

Mulberry Cogeneration Facility - Historical Annual Emissions by Unit

Year		2004			2005			2006		
Pollutant		EU 001 CT/HSRG (tpy)	EU 002 Secondary Boiler (tpy)	*Total (tpy)*	EU 001 CT/HSRG (tpy)	EU 002 Secondary Boiler (tpy)	*Total (tpy)*	EU 001 CT/HSRG (tpy)	EU 002 Secondary Boiler (tpy)	*Total (tpy)*
Volatile Organic Compounds	VOC	21.3	0.0046	*21.3*	22.8	0.0260	*22.9*	21.5	0.0060	*21.5*
Sulfur Dioxide	SO_2	0.035	0.000068	*0.04*	0.230	0.002300	*0.23*	0.219	0.000500	*0.22*
Particulate Matter	PM	23.6	0.045	*23.7*	25.4	0.252	*25.7*	23.9	0.055	*24.0*
Nitrogen Oxides	NO_x	48.8	0.175	*49.0*	40.9	0.913	*41.8*	56.1	0.239	*56.3*
Carbon Monoxide	CO	68.3	0.0	*68.3*	28.0	0.0	*28.0*	34.6	0.0	*34.6*
Particulate Matter 10	PM_{10}	11.3	0.0099	*11.3*	12.2	0.0550	*12.2*	11.5	0.0120	*11.5*

Source: AOR Data

TABLE 3

Mulberry Cogeneration Past Actual Facility Annual Emissions

Year		2001	2002	2003	2004	2005	2006	2002- 2006 Existing Emissions Highest 2 Year Avg.
Pollutant		**Total (tpy)**	**Total (tpy)**	**Total (tpy)**	**Total (tpy)**	**Total (tpy)**	**Total (tpy)**	**Total (tpy)**
Volatile Organic Compounds	**VOC**	23.0	20.4	**23.5**	**21.3**	22.9	21.5	22.4
Sulfur Dioxide	**SO_2**	1.7	**1.5**	**1.8**	0.0	0.2	0.2	1.7
Particulate Matter	**PM**	25.6	22.7	**26.1**	**23.7**	25.7	24.0	24.9
Nitrogen Oxides	**NO_x**	62.6	46.6	46.6	49.0	**41.8**	**56.3**	49.1
Carbon Monoxide	**CO**	6.8	26.2	8.3	**68.3**	**28.0**	34.6	48.1
Particulate Matter 10	**PM_{10}**	12.3	10.9	**12.5**	**11.3**	12.2	11.5	11.9

Source: AOR Data

Bold denotes highest 2 years in the 2002-2006 timeframe

TABLE 4

Mulberry Cogeneration Facility Emissions Increase

Pollutant	Existing Emissions (tpy) Highest 2-year avg.	Proposed Emissions[1] 6% Increase (tpy)	Net Increase or Decrease (tpy)	PSD Significant Emission Thresholds (tpy)	PSD Applicable (Yes/No)
VOC	22.4	23.7	1.3	40	NO
SO_2	1.7	1.8	0.1	40	NO
PM	24.9	26.4	1.5	25	NO
NO_x	49.1	52.0	2.9	40	NO
CO	48.1	51.0	2.9	100	NO
PM_{10}	11.9	12.6	0.7	15	NO

TABLE 5

Estimated Increase for Previous 5 Percent Heat Input Increase *

* *(Permit No. 1050217-005-AV)*

Pollutant	Existing Emissions (tpy) Highest 2-year avg.	Proposed Emissions[2] 5% Increase (tpy)	Net Increase or Decrease (tpy)	PSD Significant Emission Thresholds (tpy)	PSD Applicable (Yes/No)
VOC	23.3	24.4	1.2	40	NO
SO_2	1.8	1.9	0.1	40	NO
PM	25.9	27.1	1.3	25	NO
NO_x	71.5	75.1	3.6	40	NO
CO	47.3	49.6	2.4	100	NO
PM_{10}	12.4	13.0	0.6	15	NO

[1] Proposed emissions calculated based on percent increase in emissions of highest 2-year average (years 2002-2006).

[2] Proposed emissions calculated based on percent increase in emissions of highest 2-year average (years 2000-2004).

TABLE 6

Mulberry Cogeneration Facility Contemporaneous Netting Summary

Pollutant	Existing Emissions (tpy) Highest 2-year avg.	Net Increase or Decrease (tpy)	PSD Significant Emission Thresholds (tpy)	PSD Applicable (Yes/No)
VOC	22.4	2.5	40	NO
SO2	1.7	0.2	40	NO
PM	24.9	2.8	25	NO
NOx	49.1	6.5	40	NO
CO	48.1	5.3	100	NO
PM10	11.9	1.3	15	NO