**FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION**

NORTHEAST DISTRICT
8800 BAYMEADOWS WAY WEST, SUITE 100
JACKSONVILLE, FLORIDA 32256

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SECRETARY

*Sent by Electronic Mail – Received Receipt Requested*

**PERMITTEE**

City of Gainesville, GRU
Post Office Box 147117 (A132)
Gainesville, FL 32614-7117

Authorized Representative:
Mr. John W. Stanton, Asst. General Manager

Air Permit No. 0010129-004-AC
Permit Expires: DRAFT

City of Gainesville, GRU
Air Construction Permit
Modifications to EU001 EU002

This is the final air construction permit, which authorizes the addition of Specific Condition Number 2, Section 3: Combustion Turbine Generators (CTGs) Heat Recovery Steam Generators (HRSGs) Unit No.1 and Unit No. 2. to allow flexibility to replace the stationary combustion turbines with equivalent "like kind" overhauled or new combustion turbines. The proposed work will be conducted at the City of Gainesville, GRU South Energy Center, which is an establishment engaged in electric power generation (Standard Industrial Classification No. 4911). The existing facility is located at 1390 SW 14th Avenue, Gainesville in Alachua County, FL. The UTM coordinates are Zone 17, 370.29 km East; 3,279.46 km N.

This final permit is organized by the following sections.

Section 1. General Information

Section 2. Administrative Requirements

Section 3. Emissions Unit Specific Conditions

Section 4. Appendices

Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of Section 4 of this permit.

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 conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and is not subject to the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Upon issuance of this final permit, 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 30 days after this order is filed with the clerk of the Department.

Executed in Jacksonville, Florida

(DRAFT)

Khalid Al-Nahdy, P.E. (Date)
District Air Program Administrator

## CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Permit package (including the Final Determination and Final Permit) was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested before the close of business on _____ to the persons listed below.

John W. Stanton, Assistant General Manager, City of Gainesville GRU stantonjw@gru.com
Regina Embry, Electric Utility Engineer, City of Gainesville GRU embryrg@gru.com

Clerk Stamp

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

_____ _____
(Clerk) (Date)

## FACILITY AND PROJECT DESCRIPTION

### Existing Facility

The facility is permitted to construct two combustion turbine generators (CTGs), two fired heat recovery steam generators (HRSGs), one auxiliary steam boiler, three small cooling towers, and three emergency diesel-engine driven generators. The facility has constructed and currently operates one CTG, one fired HRSG, one auxiliary steam boiler, two small cooling towers, and two emergency diesel-engine driven generators.

The facility provides steam and power to the Shands Hospital complex, as well as power to the electrical transmission grid. Equipment authorized for the South Energy Center are described as follows:

Two CTGs & HRSGs: The combustion turbine generators are permitted to fire natural gas exclusively. In simple cycle mode, the CTGs' exhaust discharge directly to the atmosphere. In combined cycle mode, the hot exhaust gas from each CTG is routed to a HRSG to generate steam. The HRSGs include natural gas fired duct burners (low NOx burners) for supplemental steam generation by the HRSGs. Following the recovery of waste heat by the HRSGs, the CTGs' exhaust gases discharge to the atmosphere.

The combustion turbine generators each have a nominal heat input of approximately 53 MMBtu/hour at 32 °F ambient temperature and a power generation capacity of approximately 4,600 kilowatts. Each HRSG can produce up to 45,000 pounds per hour of steam and includes a natural gas fired duct burner with a nominal heat input of 36 MMBtu/hour.

The CTGs & HRSG are subject to 40 CFR 60, NSPS, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines.

Auxiliary Steam Boiler: The dual fuel (natural gas and low sulfur distillate fuel oil) fired auxiliary boiler has a heat input rate of approximately 41 MMBtu/hour.

The boiler is subject to 40 CFR 60, NSPS, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. The boiler is also subject to Rule 62-296.406, F.A.C., for Fossil Fuel Steam Generators with Less Than 250 Million Btu per Hour Heat Input, New and Existing Emissions Units.

Three Emergency Diesel Engine Generators: Two emergency diesel generators each with a rated capacity of 2,250 kW. The third smaller emergency diesel generator has a rated capacity of 500 kW. The emergency generators will provide power in the event of outages.

The diesel engines are subject to 40 CFR 60, NSPS, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

## Proposed Project

This project is for an air construction permit revision, which authorizes the addition of Specific Condition Number 2 Section 3: Combustion Turbine Generators (CTGs) Heat Recovery Steam Generators(HRSGs) Unit No.1 and Unit No. 2. to allow flexibility to replace the components of the stationary gas combustion turbines with equivalent "like kind" overhauled or new combustion turbines. This project will modify the following emissions unit(s).

| **Facility ID No. 0010129** | |
|---|---|
| **ID No.** | **Emission Unit Description** |
| 001 | Combustion Turbine Generators (CTGs) Heat Recovery Steam Generators (HRSGs) Unit No.1 and Unit No. 2 |
| 002 | |

## FACILITY REGULATORY CLASSIFICATION

- The facility **is not** a major source of hazardous air pollutants (HAP).
- The facility **has no** units subject to the acid rain provisions of the Clean Air Act (CAA).
- The facility **is not** a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility **is a** synthetic Non-Title V source.
- The facility **is not** a major stationary source in accordance with Rule 62-212.400(PSD), F.A.C.

**1.** Permitting and Compliance Authority: The permitting authority for this project is the Northeast District, Florida Department of Environmental Protection (Department). The Northeast District Office's mailing address is 8800 Baymeadows Way West, Suite 100, Jacksonville, Florida 32256, 904) 256-1700. All documents related to applications for permits to operate an emissions unit shall be submitted to the Northeast District Office.

**2.** Appendices: The following Appendices are attached as part of this permit:

a. Appendix A. Citation Formats and Glossary of Common Terms;

b. Appendix B. General Conditions;

c. Appendix C. Common Conditions; and

d. Appendix D. Common Testing Requirements. (if applicable)

**3.** Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296 and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

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

**5.** Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No new emissions unit shall be constructed and no existing emissions unit shall be modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

**6.** Source Obligation:

(a) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

(b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

**7.** A completed **Application for Air Permit – Non-Title V Source** [DEP Form No. 62-210.900(3)] shall be submitted to the Department at least 60 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the permittee shall submit the appropriate application form, processing fee, and compliance test reports as required by this permit.

[Rules 62-210.300(2) and 62-4.055 F.A.C.]

This section of the permit addresses the following emissions unit:

| EU No. | Emission Unit Description |
|---|---|
| 001 | Combustion Turbine Generators (CTGs) & Heat Recovery Steam Generators (HRSGs) Unit No.1 and Unit No. 2 |
| 002 | |

The CTGs and HRSGs are subject to the following regulations.

- 40 CFR 60, NSPS, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines
- The applicable provisions of 40 CFR 60, Subpart A – General Provisions

The HRSGs are also subject to the following regulation.

- Rule 62-296.406, F.A.C. – Fossil Fuel Steam Generators with Less Than 250 MMBtu/hour of Heat Input

**ESSENTIAL POTENTIAL TO EMIT PARAMETERS**

1. **Relation to Other Permits:** The conditions of this permit will supplement and comply with conditions of all existing, valid, Department permits.

   [Rules 62-4.030, and 62-210.300(1)(b), F.A.C.]

2. **Combustion Turbine Replacements**: Replacements of the combustion turbines are authorized provided the following requirements are met.

   (a) The combustion turbines may be replaced with equivalent "like-kind" overhauled or new combustion turbines. The overhauled or new combustion turbines shall not increase the combustion turbines maximum heat input rate or potential emissions. The replacement overhauled or new combustion turbines shall be designed to achieve the emissions standards specified in this permit.

   (b) Within 90 days of replacing a combustion turbine generator, the permittee shall conduct emissions stack tests to demonstrate compliance with the emission standards for NOx, and visible emissions. Performance testing and compliance demonstrations for the replacement combustion turbines shall be conducted in accordance with Specific Conditions 9 through Specific Conditions 19. The permittee shall comply with the requirements for notification, test methods, test procedures, and reporting required by this permit.

Specific Condition 2. Continued:

(c). The permittee shall submit an application for an air construction permit prior to replacing a combustion turbine with an overhauled or new combustion turbine if the replacement results in an increase in combustion turbine maximum heat input rate or potential emissions.

[Application for permit revision received October 24, 2012]

**3. Hours of Operation:** The hours of operation are not restricted.

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

**4. Method of Operation:** The CTG is natural gas fired only and can be operated in simple cycle mode without the HRSG or combined cycle mode with the HRSG. The HRSG duct burners shall fire natural gas only. The HRSG shall not be operated independent of the CTG.

[Rules 62-4.160(2) & (14)(b) & 62-210.200(PTE), F.A.C.; Project 0010129-003-AF]

**5. Maximum Heat Input Rates:** The maximum heat input rates for the CTGs and the HRSGs are as described below.

| Emission Units | Maximum Heat Input Rate (MMBtu/hour, HHV @ 32 °F) | |
|---|---|---|
| | Combustion Turbine Generators | Heat Recovery Steam Generators |
| 001& 002 | 53 | 35.5 |

*Permitting Note*: The peak load of each CTG is 45.1 MMBtu/hour at ISO conditions.

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

[Rules 62-4.160(2) & (14)(b), 62-210.200(PTE), F.A.C.]

## EMISSION LIMITATION AND PERFORMANCE STANDARDS

6. **Emissions Limits**: The units are subject to the following emissions limiting standards

| Pollutant | Emissions Limit | Rule | Unit |
|---|---|---|---|
| Nitrogen Oxide (NOx) | 42 ppmvd @ 15% O2 **OR**<br><br>290 ng/J (2.3 lb/MWh) of useful output | 40 CFR 60.4320 (a)<br>40 CFR 60.4305;<br>Table 1 of 40 CFR 60 Subpart KKKK | CTGs and HRSGs |
| Sulfur Dioxide (SO2) | Shall not burn any fuel which contains total potential sulfur emissions in excess of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input, **OR**<br><br>Shall not cause to be discharged into the atmosphere any gases which contain SO2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output | 40 CFR 60.4330 (a)(1) & (2)<br>40 CFR 60.4305 | CTGs and HRSGs |
| Visible Emissions (VE) | Shall not exceed 20 percent opacity except for one six-minute period per hour during which opacity shall not exceed 27 percent | Rule 62-296.406(1), F.A.C. | HRSGs |

[Air Construction Permit No. 0010129-001-AC]

7. **Best Available Control Technology (BACT)- HRSGs**: The amount of particulate matter and sulfur dioxide emissions from each Heat Recovery Steam Generator shall be limited by the firing of natural gas in the duct burner.

   [Rule 62-296.406(2) & (3), F.A.C., BACT Determination dated July 25, 2007]

8. **General Requirements**: The owner or operator shall operate and maintain the stationary combustion turbines, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing air pollution at all times including during startup, shutdown, and malfunction.

   [40 CFR 60.4333(a)]

**PERFORMANCE TESTING AND COMPLIANCE DEMONSTRATION FOR NOX EMISSIONS LIMIT**

9. **Initial and Subsequent Performance Tests for NOx**: The owner or operator shall conduct an initial performance test, as described by 40 CFR 60.8. Subsequent tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test), in accordance with the requirements stated in Specific Condition Nos. 10 -13 to demonstrate continuous compliance. If the NOx emissions result from the performance test is less than or equal to 75% of the NOx emissions limit for the combustion turbine, the owner or operator may reduce the subsequent performance to once every two years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75% of the NOx emissions limit for the turbine, the owner or operator shall resume annual performance tests.

   [40 CFR 60. 4340(a) and 40 CFR 60.4400(a)]

10. **NOx Performance Tests Requirements**: There are two general methodologies that the owner or operator may use to conduct the performance tests. For each run:

    (i) Measure the NOx concentration (in part per million (ppm)), using EPA Method 7E or EPA Method 20 in Appendix A of this permit. For units complying with the output based standard, concurrently measure the stack gas flowrate using EPA Method 1 and 2 in Appendix A of this permit, 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

    $1.194 \times 10^{-7}$ = 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 40 CFR 60.4350(f)(2); **or**

Specific Condition 10. Continued:

(ii) Measure the $NO_x$ and diluent gas concentrations, using either EPA Method 7E and 3A, or EPA Method 20. 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 to calculate the $NO_x$ emission rate in lb/MMBtu. Then, use equation 1, and if necessary, use equation 2 and 3 in 40 CFR 60.4350(f) to calculate the $NO_x$ emission rate in lb/MWh.

[40 CFR 60.4400(a)(1) and Permit No. 0010129-003-AF]

**11**. **<u>NOx Performance Tests- Sampling Traverse Points Requirements</u>**: Sampling traverse points for $NO_X$ 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.

[40 CFR 60.4400(a)(2)]

**12.** Notwithstanding Specific Condition 11 of this section, the owner or operator may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in Appendix A of this permit if the following conditions are met:

(i) The owner or operator may perform a stratification test for $NO_X$ and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of 40 CFR 75.

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

(A) If each of the individual traverse point $NO_X$ 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 $CO_2$ (or $O_2$) from the mean for all traverse points, then the owner or operator shall 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 $NO_X$ concentration during the stratification test; or

Specific Condition 12. Continued:

(B) For turbines with a $NO_X$ standard greater than 15 ppm @ 15% $O_2$, the owner or operator shall 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 $NO_X$ 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 $CO_2$ (or $O_2$) from the mean for all traverse points; or

(C) For turbines with a $NO_X$ standard less than or equal to 15 ppm @ 15% $O_2$, the owner or operator shall 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 $NO_X$ 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 $CO_2$ (or $O_2$) from the mean for all traverse points.

[40 CFR 60.4400(a)(3)]

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

(i) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), the owner or operator shall measure the total $NO_X$ emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(ii) Compliance with the applicable emission limit shall be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average $NO_X$ emission rate at each tested level meets the applicable emission limit.

(iii) The ambient temperature must be greater than 0 °F during the performance test.

[40 CFR 60.4400(b)(2), (4), and (6)]

**PERFORMANCE TESTING AND COMPLIANCE DEMONSTRATION FOR SULFUR DIOXIDE (SO2) LIMIT**

**14. Initial and Subsequent Performance Tests for SO2:** The owner or operator shall conduct an initial performance test, as required in 40 CFR 60.8. Subsequent $SO_2$ 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 the owner or operator may use to conduct the performance tests.

(a) If the owner or operator chooses 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 40 CFR 60.17) for natural gas or ASTM D4177 (incorporated by reference, see 40 CFR 60.17) for oil. Alternatively, for oil, the owner or operator may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see 40 CFR 60.17). The fuel analyses may be performed either by the owner or operator, a service contractor retained by the owner or operator, 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 40 CFR 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 40 CFR 60.17).

(b) Measure the $SO_2$ 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 40 CFR 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 permit, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the $SO_2$ emission rate:

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

Specific Condition 14.(b) Continued:

Where:

E = $SO_2$emission rate, in lb/MWh

$1.664 \times 10^{-7}$= conversion constant, in lb/dscf-ppm

$(SO_2)_c$= average $SO_2$concentration for the run, in ppm

$Q_{std}$= 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 §60.4350(f)(2) ; or

(c) Measure the $SO_2$ and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in Appendix A of this permit. In addition, the owner or operator may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 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 permit to calculate the $SO_2$emission rate in lb/MMBtu. Then, use equation 1, and if necessary, use equation 2 and 3 in §60.4350(f) of to calculate the $SO_2$ emission rate in lb/MWh.

[40 CFR 60.4415]

**15. <u>Fuel's Sulfur Content Monitoring- CTGs</u>**: The owner or operator shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in specific condition No. 16. The sulfur content of the fuel must be determined using total sulfur methods described in specific condition No.14. 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 40 CFR 60.17), which measure the major sulfur compounds, may be used.

[40 CFR 60.4360]

**16.** **Fuel's Sulfur Content Monitoring Exemption- CTGs**: The owner or operator 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 $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input. The owner or operator shall 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 $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng $SO_2$/J (0.42 lb $SO_2$/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 $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for continental areas or 180 ng $SO_2$/J (0.42 lb $SO_2$/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 40 CFR 75 is required.

[40 CFR 60.4365]

**17.** **The Frequency of Determining the Sulfur Content of the Fuel**: The frequency of determining the sulfur content of the fuel shall be as follows:

(a) *Gaseous fuel.* If the owner or operator elects not to demonstrate sulfur content using options in specific condition No.16, 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.

(b) *Custom schedules.* Notwithstanding the requirements of paragraph (a) of this condition, 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 (b)(1) and (b)(2) of this condition, custom schedules shall be substantiated with data and shall be approved by the Department before they can be used to comply with the standard in Specific Condition No. 6 .

(1) The two custom sulfur monitoring schedules set forth in paragraphs (i) through (iv) and in paragraph (b)(2) of this condition are acceptable, without prior Department 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.

Specific Condition 17.(b) (1) Continued:

(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 (b)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (b)(1)(iii)(B) of this condition.

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

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

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (b)(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 (b)(1)(ii) or (iii) of this condition 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 40 CFR75 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 40 CFR 60, subpart KKKK.

(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.

Specific Condition 17.(b) (2) Continued:

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

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

[40 CFR 60.4370]

**PERFORMANCE TESTING AND COMPLIANCE DEMONSTRATION FOR OPACITY LIMIT**

**18**. Visible Emissions Performance Testing- HRSGs:

(a) Initial Visible Emissions Testing Requirement (EU 002): the owner or operator shall conduct a visible emissions test for the Heat Recovery Steam Generator within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup to demonstrate compliance with the emission limit in Specific Condition No. 6.

(b). Subsequent Testing Requirement– (EU 001 and 002): The owner or operator shall conduct a visible emissions test for the Heat Recovery Steam Generators to demonstrate compliance with the emission limit in Specific Condition No. 6. once every 5 years, prior to obtaining a renewed operating permit. The test method for visible emissions shall be DEP Method 9. The test shall be conducted by an observer certified in accordance with the requirements of Rule 62-297.320, F.A.C. – Standards for Persons Engaged in Visible Emissions Observations. For a combined cycle and CHP turbine systems with supplemental heat (duct burner), the owner or operator shall measure the opacity of the visible emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

[Rules 62-4.070, 62-296.406, 62-297.310(7)(a)3. and 4., 62-297.320, F.A.C., Permit No. 0010129-001-AC]

**EXCESS EMISSIONS AND MONITORING DOWNTIME FOR $SO_2$**

**19. Fuel Sulfur Content - Definition of Excess Emissions and Monitoring Downtime:** If the owner or operator chooses 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 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.

Specific Condition 19. Continued:

(b) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour 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.

[40 CFR 60.4385(a) and (c)]

**REPORTING REQUIREMENTS**

**20.** Fuel Sulfur Content – Excess Emissions Report- CTGs: For the unit that is required to periodically determining the fuel sulfur content, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

For the unit that performs annual performance tests, the owner or operator shall 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.

[40 CFR 60.4375(a)]

21. $NO_x$ and $SO_2$ Performance Test Reports- CTGs: For the unit that performs annual performance tests in accordance with Specific Condition No. 9., the owner or operator shall 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.

[40 CFR 60.4375(b)]

**22.** All reports required under 40 CFR 60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

[40 CFR 60.4395]