PERMITTEE

City of Gainesville
GRU South Energy Center
Post Office Box 147117 (A132)
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PERMITTING AUTHORITY

Florida Department of Environmental Protection
Air Resource Section
Northeast District Office
7825 Baymeadows Way, Suite B-200
Jacksonville, FL 32256-7590

PROJECT

Project No. 0010129-003-AF
Application for Non-Title V Operation Permit Revision

GRU South Energy Center is an existing facility that generates electric power (Standard Industrial Classification No. 4911). The facility is located in Alachua County at SW 14th Street between SW 13th and SW 14th Avenues, Gainesville, Florida.

On March 4, 2011, the Department received an application to revise the visible emissions compliance testing frequency from annual to every five years, prior to permit renewal, for both Emission Unit Nos. 001 and 003 at the GRU South Energy Center.

As stated in the Technical Evaluation and Preliminary Determination, the combustion turbine and the heat recovery steam generator is subject to 40 CFR 60 Subpart KKKK - Standards of Performance for Stationary Combustion Turbines and the heat recovery steam generator is also subject to State Rule 62-296.406, F.A.C. – Fossil Fuel Steam Generators with Less Than 250 MMBtu/hour of Heat Input.

In accordance with§ 60.4315 of 40 CFR 60 Subpart KKKK, the pollutants regulated by this subpart are nitrogen oxide (NOX) and sulfur dioxide (SO2). There is not an applicable Visible emission standard under this subpart.

Rule 62-296.406(1), F.A.C. establishes a visible emissions standard of 20 percent opacity except for either one six-minute period per hour during which opacity shall not exceed 27 percent, or one two-minute period per hour during which opacity shall not exceed 40 percent.

Rule 62-297.310 (7)(a)4.a., F.A.C., states that if there is an applicable standard, a formal compliance test shall be conducted for visible emissions during each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit. This rule does allow for exceptions to the annual visible emissions compliance test if they are established by rule, order, or permit.

Rule 62-297.310(7)(a)3., F.A.C. requires an emissions unit that is subject to any emission limiting standard to conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit.

Based on these rules, and since the only permitted fuel is natural gas for this emissions unit, the Department revised the visible emissions testing frequency for Emission Unit 001 to once every 5 years, prior to obtaining a renewed operating permit.

As stated in the Technical Evaluation and Preliminary Determination, the auxiliary boiler is subject to 40 CFR 60, NSPS, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, and 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.

In correspondence received on May 2, 2011, EPA stated that the opacity standard of 40 CFR 60.43c(c) applies when the unit fires one of the stated fuels, i.e. coal, oil, or wood, and not when firing natural gas. As such, if the boiler ever fires No. 2 fuel oil, it must conduct a visible emissions tests within 180 days of initially firing the fuel oil. Subsequent visible emissions testing is required pursuant to the provisions of the 40 CFR 60 Subpart Dc.

Rule 62-296.406(1), F.A.C. establishes a visible emissions standard of 20 percent opacity except for either one six-minute period per hour during which opacity shall not exceed 27 percent, or one two-minute period per hour during which opacity shall not exceed 40 percent.

If the boiler only fires natural gas, then Rule 62-297.310 (7)(a)4.a., F.A.C. allows for exceptions to the annual visible emissions compliance test if they are established by rule, order, or permit.

Rule 62-297.310(7)(a)3., F.A.C. requires an emissions unit that is subject to any emission limiting standard to conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit.

Based on these rules, the Department revised the visible emissions testing frequency for Emission Unit 003 to once every 5 years, prior to obtaining a renewed operating permit if the boiler only fires natural gas. If the boiler ever fires No. 2 fuel oil, then the visible emissions testing frequency is established by the provisions of 40 CFR 60 Subpart Dc.

Because these changes to the permit constitute a material change from the existing permit, a publication of a Public Notice was required in accordance with Rule 62-210.300(2)(b)b., F.A.C.

NOTICE AND PUBLICATION

The Department distributed a draft FESOP permit package on May 5, 2011. The applicant published the Public Notice in The Gainesville Sun on May 12, 2011. The Department received the proof of publication on May 13, 2011 electronically, followed by a hard copy received on May 16, 2011. No requests for administrative hearings or requests for extensions of time to file a petition for administrative hearing were received.

COMMENTS

Public

No comments on the Draft Permit were received from the public.

Applicant

On May 26, 2011, the Department received a comment/request from the applicant. The following summarizes the comment and the Department's response.

Ms. Regina Embry, GRU, requested that the Condition No. 16, Subsection B., language pertaining to the NOx emissions test method for the auxiliary boiler be re-written to be similar to the language specifying the NOx emissions test method for the CTG and HRSG (Emission Unit 001).

Specifically Ms. Embry requested the following language:

PERFORMANCE TESTING AND COMPLIANCE DEMONSTRATION FOR NOX EMISSIONS CAP

16. Nitrogen Oxides Emissions testing shall comply with Rule 62-297.401(7)(e), F.A.C. The test result shall be used to estimate the annual NOx emissions generated from the unit and demonstrates that the facility is meeting the facility wide NOx emissions cap of 90 tons per any 12-consecutive month period.

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. For units complying with a mass based emission standard, concurrently measure the stack gas flowrate using EPA Method 1 and 2.. Then, use the following equation to calculate the NOx emission rate:

*E = 1.194X10-7 * (NOX)c * Qstd*

Where:

E = NOx emission rate, in lb/hr
1.194 x 10-7 = conversion constant
(NOx)c = average NOx concentration for the run, in ppm.

Qstd = stack gas volumetric flow rate, in scf/hr

Note: NOX and Flow must both be on same moisture basis (wet or dry)

or

(ii) Measure the NOx and diluent gas (O2 or CO2) concentrations using EPA Method 7E and 3A. Concurrently measure and record the heat input to the unit, using a fuel flowmeter (or flowmeters). Use EPA Method 19 to calculate the NOx emission rate in lb/MMBtu. Then, calculate the mass emissions using the following formula:

NOX lb/hr = NOX#/mmBu X Heat Input

Where:

Heat Input = mmBTU/hr calculated from fuel flowmeters and HHV of the fuel

(iii) Sampling Traverse Points Requirements: Sampling traverse points for NOx and diluent gas are to be selected following 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. The owner or operator 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 diluent concentrations differs by no more than ±0.15 percent CO2 (or O2) from the mean for all traverse points.

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Response: A review of the proposed test method was conducted by the Division of Air. It was determined that it doesn't appear that either 40 CFR 60 Subpart Dc or EPA Method 19 prevents the use of EPA Method 19 at the auxiliary boiler for this purpose. However, such a change in the compliance method requires a public notice in accordance with Rule 62-210.300(2)(b)1.b., F.A.C.

The Department discovered a typographical error in Specific Condition No. 10 of Subsection A of the permit. The recommended administrative changes were noted below. ~~Strikethrough~~ indicates deleted text; double-underline indicates added text.

10. NO_x 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 NO_x concentration (in part per million (ppm)), using EPA Method 7E or EPA Method 20. For units complying with the output based standard, concurrently measure the stack gas flowrate using EPA Method 1 and 2, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_x emission rate:

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

    Where:

    E = NO_x emission rate, in lb/MWh

    1.194×10^{-7} = conversion constant, in lb/dscf-ppm

    $(NO_x)c$ = average NO_x 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 ~~specific condition No. 15. of this section~~ 40 CFR 60.4350(f)(2); **or**

    (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 ~~specific condition No. 15. of this section~~ 40 CFR 60.4350(f) to calculate the NO_x emission rate in lb/MWh.

[40 CFR 60.4400(a)(1)]

The Department discovered a typographical error in Specific Condition No. 14 of Subsection A of the permit. The recommended administrative changes were noted below. ~~Strikethrough~~ indicates deleted text; double-underline indicates added text.

14. SO_2 Performance Tests Requirements & Frequency: Performance tests for SO_2 emissions 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:

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

Where:

E = SO_2 emission rate, in lb/MWh

1.664×10^{-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 to ~~specific condition No. 13 of this section~~ 40 CFR 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 ~~Specific Condition No. 13. of this section~~ 40 CFR 60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

[40 CFR 60.4415]

The Department discovered a typographical error in Specific Condition No. 14 of Subsection B of the permit. The recommended administrative changes were noted below. ~~Strikethrough~~ indicates deleted text; double-underline indicates added text.

14. Visible Emissions– If Fuel Oil is Fired in Boiler: The owner or operator of an affected facility combusting oil that is subject to the opacity standard in Specific Condition No. 4.a. shall conduct a performance test using Method 9 of appendix A–4 of Part 60 and the procedures in 40 CFR 60.11 to demonstrate compliance with the emission limit in Specific Condition No. 4.a. within 180 days of initially firing the oil in the boiler.

    The performance test shall be conducted while the affected facility is combusting oil. The observation period for the Method 9 of appendix A–4 of Part 60 performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

    The owner or operator shall also comply with either paragraphs (1), (2), or (3) of this Specific Condition.

    (1) Except as provided in paragraph (2) and (3) of this Specific Condition, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of Part 60 performance tests using the procedures in this Specific Condition according to the applicable schedule in paragraphs (1)(i) through (1)(iv) of this Specific Condition, as determined by the most recent Method 9 of appendix A–4 of Part 60 performance test results.

        (i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of Part 60 performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

        (ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of Part 60 performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted;

        (iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of Part 60 performance test must be

completed within 3 calendar months from the date that the most recent performance test was conducted; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of Part 60 performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of Part 60 performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of Part 60 performance tests, elect to perform subsequent monitoring using Method 22 of appendix A–7 of Part 60 according to the procedures specified in paragraphs (2)(i) and (ii) of this Specific Condition.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of Part 60 and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A–4 of Part 60 performance test using the procedures in this Specific Condition within 45 calendar days according to the requirements in ~~Specific Condition No. 13~~ 40 CFR 60.45c(a)(8) -Specific Condition No. 12a.

(ii) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of Part 60 performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (2) of this Specific Condition. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

[40 CFR 60.47c(a)]

On July 5, 2011, the Department withdrew the draft permit revision issued on May 5, 2011 and replaced it with a revised draft permit that included the above changes as well a Public Notice requirement.

The applicant published the Public Notice in The Gainesville Sun on July 14, 2011. The Department received the proof of publication on July 15, 2011 electronically, followed by a hard copy received on July 18, 2011. No requests for administrative hearings or requests for extensions of time to file a petition for administrative hearing were received.

COMMENTS

Public/Applicant

No comments on the Revised Draft Permit were received from the public. On July 25, 2011 Ms. Regina Embry, GRU raised a question concerning the expected operating rate during Visible Emissions testing of the auxiliary boiler. It was decided to include the following language in Specific Condition No. 12 of Subsection B to provide clarification that the Common Testing Requirements of Appendix D, are applicable to this emissions unit.

"The test shall be conducted in accordance with the applicable requirements specified in Appendix D (Common Testing Requirements) of this permit."

CONCLUSION

The final action is to issue the permit with the minor changes, corrections and clarifications as described above.