Memorandum

Florida Department of Environmental Protection

TO:	Trina Vielhauer
FROM:	Al Linero *aal*
DATE:	March 24, 2008
SUBJECT:	OUC Stanton Unit B Draft Air Permit No. 0950137-020-AC (PSD-FL-373A) 300 MW Natural Gas-fueled Combined Cycle Unit

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft Permit; and
- PE Certification

This draft permit is to construct a natural gas-fueled combined cycle (NGCC) unit at the OUC Curtis H. Stanton Energy Center in Orange County, Florida. Upon issuance of a final permit, we will rescind the previously issued permit to construct an integrated coal gasification and combined cycle (IGCC) unit at the Stanton Plant.

Day 90 is June 3, 2008. I recommend your approval of the attached Draft Permit package for this project.

AAL/aal

Attachments

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor
Jeff Kottkamp
Lt. Governor
Michael W. Sole
Secretary

March 25, 2008

Electronically Sent – Received Receipt Requested.

Ms. Denise Stalls DStalls@ouc.com
Vice President Environmental Affairs
Orlando Utilities Commission
500 South Orange Avenue
Post Office Box 3193
Orlando, Florida 32802

Re: Curtis H. Stanton Energy Center Unit B
Natural Gas-Fueled Combined Cycle Unit
DEP File No. 0950137-020-AC (PSD-FL-373A)

Dear Ms. Stalls:

On March 4, 2008 you submitted an application for an air construction permit pursuant to the rules for the Prevention of Significant Deterioration (PSD Permit) in accordance with Rule 62-212.400, Florida Administrative Code to construct a natural gas-fueled combined cycle unit (Unit B) at the facility identified above. Enclosed are the following documents:

- The Technical Evaluation and Preliminary Determination summarizes the Permitting Authority's technical review of the application and provides the rationale for making the preliminary determination to issue a Draft Permit.
- The proposed Draft PSD Permit includes the specific conditions that regulate the emissions units covered by the proposed project.
- The Written Notice of Intent to Issue PSD Permit provides important information regarding: the Permitting Authority's intent to issue a PSD Permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue a PSD Permit; the procedures for submitting comments on the Draft PSD Permit; the process for filing a petition for an administrative hearing; and the availability of mediation.
- The Public Notice of Intent to Issue PSD Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact the Project Engineer, David Read, at 414-7236 or Alvaro Linero, Program Administrator, at 850-921-9523.

Sincerely,

Trina L. Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures
TLV/aal/dr

P.E. CERTIFICATION STATEMENT

PERMITTEE

Orlando Utilities Commission (OUC)
5100 South Alafaya Trail
Orlando, Florida 32831

Curtis H. Stanton Energy Center Unit B
DEP File No. 0950137-020-AC
Permit No. PSD-FL-373A

PROJECT DESCRIPTION

The project is a nominal 300 megawatts (MW) natural gas fueled combined cycle (NGCC) unit (Stanton Unit B) and ancillary equipment at the facility identified above. The project consists of: a nominal 150 MW General Electric 7FA combustion turbine-electrical generator, a duct fired heat recovery steam generator, a nominal 150 MW steam-electrical generator, a nominal 205-foot stack, a mechanical draft cooling tower with drift eliminators and a nominal 1,000,000 gallon fuel oil storage tank. Back-up ultra low sulfur diesel (ULSD) fuel oil (0.0015 percent sulfur) will be burned for a maximum of 1000 hours per year. OUC's estimates of maximum potential annual emissions from the proposed NGCC project are summarized in the following table. The emissions from the former integrated coal gasification and combined cycle (IGCC) design are included for comparison.

POLLUTANTS	IGCC Case Potential Emissions Tons Per Year	NGCC Case Potential Emissions Tons Per Year	PSD Significant Emission Rate Tons Per Year
CO	654	163	100
NO_X	1006 (-19)*	80	40
PM/PM_{10}	189/179	110/109	25/15
SAM	22.4	8	7
SO_2	162	55	40
VOC	129	19	40
Mercury	0.01	0.003	0.1

* Negative value is after consideration of concurrent reductions from existing coal-fueled Units 1 and 2.

Nitrogen oxides (NO_X) emissions will be controlled by selective catalytic reduction (SCR) to achieve 2 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 8 ppmvd while burning ULSD fuel oil. Emissions of carbon monoxide (CO) will be controlled to 4.1 and 8 ppmvd while burning gas and fuel oil respectively. Emissions of particulate matter ($PM/PM_{10}/PM_{2.5}$) sulfur dioxide (SO_2), sulfuric acid mist (SAM) and volatile organic compounds (VOC) will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and ULSD fuel oil. Ammonia emissions (NH_3) generated due to NO_X control will be limited to 5 ppmvd.

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park and the Chassahowitzka Wilderness Area (i.e. PSD Class II Areas). Therefore, multi-source modeling was not required for ambient air quality standards or Class II increments. The project has no significant impact on the PSD Class I Chassahowitzka Wilderness and Everglades National Park areas. I have reasonable assurance that the proposed project will not cause or contribute to a violation of any state or federal ambient air quality standard.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features). Note that less than the typical level of detail was required given the demonstration nature of the project. Per 403.061(18), F.S., my employer, the Florida DEP has the power and the duty to encourage and conduct studies, investigations, and research relating to pollution and its causes, effects, prevention, abatement, and control.*

3/24/08

Alvaro A. Linero, P.E.
Registration Number: 26032
Date: March 24, 2008

WRITTEN NOTICE OF INTENT TO ISSUE PSD PERMIT

In the Matter of an
Application for Air Permit by:

Ms. Denise Stalls, V.P. Environmental Affairs
Authorized Representative
Orlando Utilities Commission
Post Office Box 3193
Orlando, Florida 32802

DEP File No. 0950137-020-AC
Draft Permit No. PSD-FL-373A
Curtis H. Stanton Energy Center
Combined Cycle Unit B
Orange County, Florida

Facility Location: The applicant, Orlando Utilities Commission (OUC), operates the existing Curtis H. Stanton Energy Center, which is located in Orange County at 5100 South Alafaya Trail, Orlando, Florida. The UTM coordinates for the site are 483.6 km East and 3151.1 North.

Project: On March 6, 2008 OUC submitted an application for an air construction permit pursuant to the rules for the Prevention of Significant Deterioration (PSD Permit) in Rule 62-212.400, Florida Administrative Code (F.A.C.) for a nominal 300 megawatts (MW) natural gas fueled combined cycle unit (Unit B) and ancillary equipment at the facility identified above. Details of the project are provided in the application and the enclosed Technical Evaluation and Preliminary Determination.

According to OUC the project is a revision of the combined-cycle portion of a previously permitted integrated coal gasification and combined cycle (IGCC). The new version of the project will allow firing of natural gas as the primary fuel, with ultra-low-sulfur diesel fuel serving as a backup fuel, while removing the coal handling, gasification and synthetic gas cleanup components.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters F.A.C. 62-4, 62-210, and 62-212. The proposed project is not exempt from air permitting requirements and a PSD Permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite 4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, Mail Station (MS) 5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above. In addition, electronic copies of these documents are available by entering the file number provided above where indicted on the following web site: http://www.dep.state.fl.us/air/eproducts/apds/default.asp .

Notice of Intent to Issue PSD Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final PSD Permit (and simultaneously rescind the previously issued PSD Permit for the IGCC project) in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at above address or phone number. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft PSD Permit and requests for a public meeting for a period of 30 days from the date of publication of the Public Notice. Written comments must be postmarked by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period. If written comments received result in a significant change to the Draft PSD Permit, the Permitting Authority shall revise the Draft PSD Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

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

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

Mediation: Mediation is not available in this proceeding.

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 Intent to Issue Air Permit package (including the Written Notice of Intent to Issue Air Permit, Public Notice of Intent to Issue Air Permit, the Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by electronic mail with received receipt requested before the close of business on March 25, 2008 to the persons listed:

Denise M. Stalls, OUC: dstalls@ouc.com
Mayor Buddy Dyer, Orlando: buddy.dyer@cityoforlando.net
Mayor Richard T. Crotty, Orange County: mayor@ocfl.net
Lori Cuniff, Orange County EPD: lori.cunniff@ocfl.net
Gregg Worley, U.S. EPA Region 4, Atlanta GA: worley.gregg@epa.gov
Dee Morse, National Park Service, Denver CO: dee_morse@nps.gov
Jim Bradner, DEP CD: james.bradner@dep.state.fl.us
Thomas W. Davis, P.E., ECT, Inc.: tdavis@ectinc.com
Mike Halpin, DEP Siting Office: mike.halpin@dep.state.fl.us

Clerk Stamp

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

Mary L. Harris — 3/25/08

(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation
Draft Air Permit No. 0950137-020-AC
Orlando Utilities Commission
Curtis H. Stanton Energy Center Combined Cycle Unit B
Orange County

Applicant: The applicant for this project is the Orlando Utilities Commission (OUC). The applicant's authorized representative and mailing address is: Ms. Denise Stalls, Vice President, Environmental Affairs, Orlando Utilities Commission, Post Office Box 3193, Orlando, Florida 32802.

Facility and Location: OUC operates the existing Curtis H. Stanton Energy Center, which is located in Orange County at 5100 South Alafaya Trail, Orlando, Florida. The UTM coordinates for the site are 483.6 km East and 3151.1 North. The existing facility consists of two fossil fuel fired steam electric generating units (Stanton Units 1 and 2), and one natural gas-fueled combined cycle unit (Stanton Unit A). There are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash.

Project: On March 6, 2008 OUC submitted an application for an air construction permit pursuant to the rules for the Prevention of Significant Deterioration (PSD Permit) in Rule 62-212.400, Florida Administrative Code (F.A.C.) for a nominal 300 megawatts (MW) natural gas fueled combined cycle (NGCC) unit (Stanton Unit B) and ancillary equipment at the facility identified above. A determination of best available control technology (BACT) was required for emissions of carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}) and sulfuric acid mist (SAM). Details of the project are provided in the application and the enclosed Technical Evaluation and Preliminary Determination.

The project consists of: a nominal 150 MW General Electric 7FA combustion turbine-electrical generator, a duct fired heat recovery steam generator, a nominal 150 MW steam-electrical generator, a nominal 205-foot stack, a mechanical draft cooling tower with drift eliminators and a nominal 1,000,000 gallon fuel oil storage tank. Back-up ultra low sulfur diesel (ULSD) fuel oil (0.0015 percent sulfur) will be burned for a maximum of 1000 hours per year.

According to OUC the project is a revision of the natural gas-fueled portion of a previously permitted integrated coal gasification and combined cycle (IGCC). The new NGCC version of the project will allow firing of natural gas as the primary fuel, with ULSD fuel oil serving as a backup fuel, while removing the coal handling, gasification and synthetic gas cleanup components.

OUC's estimates of maximum potential annual emissions from the proposed NGCC project are summarized in the following table. The emissions from the former IGCC design are included for comparison.

Pollutants	IGCC Case Potential Emissions Tons Per Year	NGCC Case Potential Emissions Tons Per Year	PSD Significant Emission Rate Tons Per Year
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PM/PM_{10}	189/179	110/109	25/15
SAM	22.4	8	7
SO_2	162	55	40
VOC	129	19	40
Mercury	0.01	0.003	0.1

* Negative value is after consideration of concurrent reductions from existing coal-fueled Units 1 and 2.

(Public Notice to be Published in the Newspaper)

NO_X emissions will be controlled by selective catalytic reduction (SCR) to achieve 2 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 8 ppmvd while burning ULSD fuel oil. Emissions of CO will be controlled to 4.1 and 8 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM_{10}, sulfur dioxide (SO_2), SAM and volatile organic compounds (VOC) will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and ULSD fuel oil. Ammonia emissions (NH_3) generated due to NO_X control will be limited to 5 ppmvd.

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park and the Chassahowitzka Wilderness Area (i.e. PSD Class II Areas). Therefore, multi-source modeling was not required for ambient air quality standards or Class II increments. The project has no significant impact on the PSD Class I Chassahowitzka Wilderness and Everglades National Park areas. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or contribute to a violation of any state or federal ambient air quality standard.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters F.A.C. 62-4, 62-210, and 62-212. The proposed project is not exempt from air permitting requirements and a PSD Permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite 4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, Mail Station (MS) 5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above. In addition, electronic copies of these documents are available by entering the file number provided above where indicted on the following web site: http://www.dep.state.fl.us/air/eproducts/apds/default.asp .

Notice of Intent to Issue PSD Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance (and simultaneously rescind the previously issued PSD Permit for the IGCC project) with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at above address or phone number. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

(Public Notice to be Published in the Newspaper)

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of 30 days from the date of publication of the Public Notice. Written comments must be postmarked by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

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

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

Mediation: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Orlando Utilities Commission
Curtis H. Stanton Energy Center Unit B

300-Megawatt Natural Gas-Fueled Combined Cycle Unit

Orange County

DEP File No. 0950137-020-AC
PSD-FL-373A

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Permitting South

March 25, 2008

I. APPLICATION INFORMATION

A. Applicant Name and Address

Orlando Utilities Commission (OUC)
500 South Orange Avenue
Post Office Box 3193
Orlando, Florida 32802

Authorized Representative: Denise Stalls, Vice President Environmental Affairs

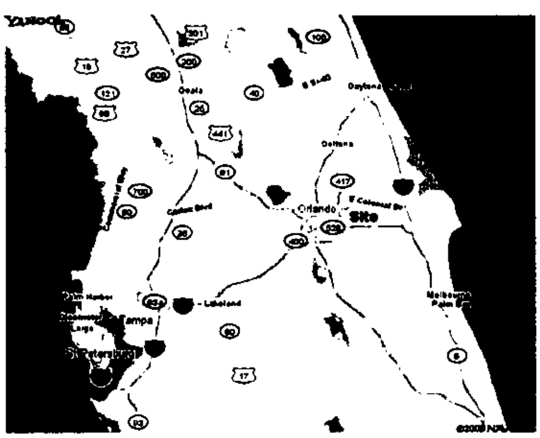
B. Processing Schedule

December 26, 2006:	Department issued Prevention of Significant Deterioration (PSD) Permit PSD-FL-373 to construct an integrated coal gasification and combined cycle (IGCC) unit at the OUC Curtis H. Stanton Energy Center (Stanton Unit B).
November 13, 2007:	Southern Power and OUC mutually agreed to terminate the IGCC Project.
March 6, 2008:	Department received a complete PSD application to construct a natural gas-fueled combined cycle (NGCC) unit in lieu of the IGCC unit.
March 25, 2008:	The Intent to Issue PSD Permit was distributed.

C. Facility Location

The OUC Curtis H. Stanton Energy Center (the Stanton Plant) is located in Orange County, Southeast of Orlando and North of Highway 528 at 5100 South Alafaya Trail. The OUC Stanton Plant presently consists of two fossil fuel-fired steam electrical generating units and a combined cycle unit. Fossil fuel-fired steam electric generating Units 1 and 2 (468 MW each) began operation in 1987 and 1996 while Combined Cycle Unit A (640 MW) began operation in 2003.

The site is located 144 km southeast from the Chassahowitzka National Wildlife Area; the nearest Federal Prevention of Significant Deterioration (PSD) Class I Area. The UTM coordinates for this site are 483.6 km East and 3151.1 North. The location of the OUC Stanton Energy Center is shown in Figure 1.



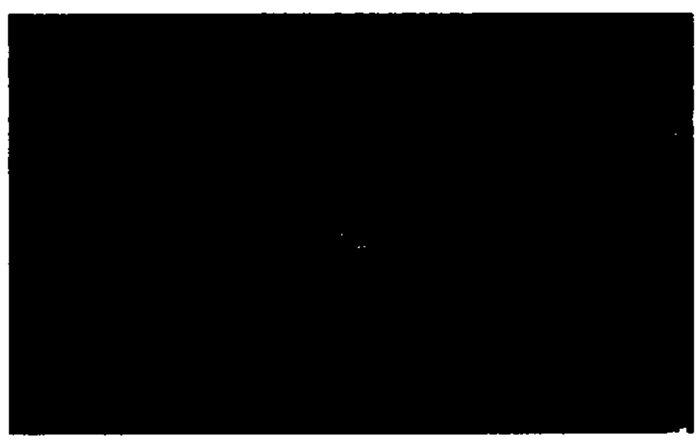


Figure 1. Project Location near Orlando. Figure 2. Aerial View of the Stanton Plant.

D. Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

E. Regulatory Classifications

40 CFR 60, Subpart KKKK. The proposed project is subject to 40 Code of Federal Regulations (CFR) 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also covers duct burners that are incorporated into combined cycle projects.

40 CFR 60, Subpart Kb. A proposed distillate fuel oil tank has a capacity greater than or equal to 40,000 gallons (151 cubic meters) and is storing a liquid with a maximum true vapor pressure less than 3.5 kPa, and is therefore not subject to Subpart Kb.

40 CFR 63, Subpart YYYY. The existing facility is a major source of hazardous air pollutants (HAP). The new unit is potentially subject to 40 CFR63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired combustion turbines such as planned for this project.

Title IV, Clean Air Act, Acid Rain Provisions. The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V, Clean Air Act, Permits. The facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year (TPY) or because it is a Major Source of HAP. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC) and sulfuric acid mist (SAM).

Prevention of Significant Deterioration (PSD). The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is classified as a "Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input", which is one of the facility categories with the PSD applicability threshold of 100 tons per year (TPY). Potential emissions of at least one regulated pollutant exceed 100 TPY per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 Florida Administrative Code (F.A.C.).

Siting. The facility was originally certified pursuant to the power plant siting provisions of Chapter 62-17, F.A.C. The certification was modified to include the IGCC project.

II. PROPOSED PROJECT SUMMARY

A. Project Description

Instead of the planned IGCC project, the applicant proposes to construct a "one-on-one" F-Class NGCC unit (Stanton Unit B) and associated auxiliary equipment. Unit B will consist of: one nominal 150 megawatts (MW) General Electric 7241 FA combustion turbine-electrical generator (CTG); a supplementary fired heat recovery steam generator (HRSG) with natural gas fueled duct burners; and a nominal 150 MW steam turbine generator (STG) for an overall nominal rating of 300 MW. The project includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements.

According to OUC the project is a revision of the previously permitted IGCC. The NGCC version of the project will allow firing of natural gas as the primary fuel, with ultralow sulfur diesel (ULSD) fuel oil serving as a backup fuel, while removing the coal handling, gasification and synthetic gas cleanup components.

Auxiliary equipment includes the following: a nominal 1,000,000 gallon tank for the storage of ultralow sulfur diesel (ULSD) fuel oil; a six-cell mechanical draft cooling tower equipped with drift eliminators; and a 205-foot exhaust stack.

- Fuel: Stanton Unit B will use natural gas as the primary fuel for up to 8760 hours per year, and ULSD fuel oil (0.0015% Sulfur) as a backup fuel. The applicant requests operation with ULSD fuel oil up to 1000 hours per year.
- Generating Capacity: The combustion turbine has a nominal generating capacity of 150 MW. The duct-fired HRSG provides steam to the steam turbine electrical generator, which has a nominal capacity of 150 MW. The total nominal generating capacity of Stanton Unit B is 300 MW.
- Controls: CO and $PM/PM_{10}/PM_{2.5}$ will be minimized by the efficient combustion of natural gas and ULSD fuel oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and ULSD fuel oil. NO_X emissions will be reduced with dry low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions during combined cycle operation.
- Continuous Emissions Monitoring Systems (CEMS): The combustion turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same CEMS as well as CO CEMS are employed for demonstration of continuous compliance with certain Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: The heat recovery steam generator has a combined cycle stack (HRSG stack) that is 205 feet tall with a nominal exit diameter of 20 feet (±1 foot). The following table summarizes the exhaust characteristics at 100 % load and with duct burners on.

Table 1 lists the nominal characteristics of Stanton Unit B when referenced to 20 degrees Fahrenheit (°F). This temperature occurs very infrequently in Central Florida, but reflects the conditions of maximum air density and therefore greatest throughput, fuel consumption and combustion turbine (CT) power production.

Table 1. Exhaust Characteristics of Unit 1 at 100% Load and 20 °F

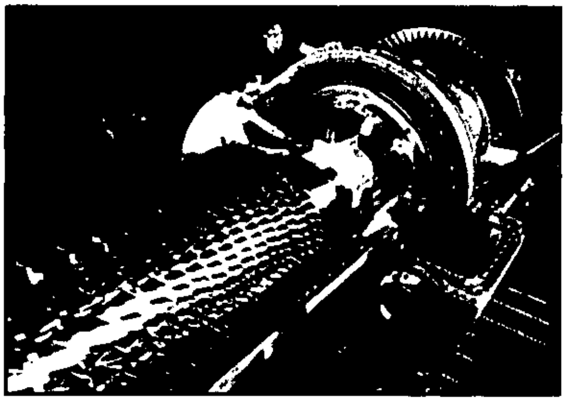
Fuel	Heat Input of CT (HHV)*	Compressor Inlet Temp.	Turbine Exhaust Temp., °F	Stack Exit Temp., °F	Stack Flow ACFM
Gas	1925 mmBtu/hour	20° F	1,073° F	227 °F	1,031,061
ULSD F.O.	2100 mmBtu/hour	20° F	1,121° F	262 °F	1,239,934

* Duct burners are used at higher temperatures and account for an additional 450 mmBtu of heat input.

B. Process Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7241FA CTG (also called a 7FA) where it is compressed by a pressure ratio of about 15 times atmospheric pressure. Figure 3 is a photograph from the GE website of a "7FA on the half-shell" with the compressor section in the foregrounds and the rotor (expansion) section in the rear.

The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors. A preassembled 7FA is shown in Figure 4 prior to coupling with the rest of the components.



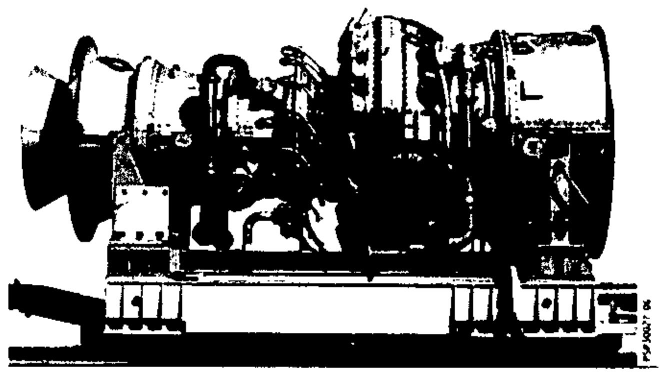


Figure 3. A GE 7FA on a half-shell. Figure 4. Preassembled GE 7FA ready for shipping.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine -section at temperatures of approximately 2500 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent (%) is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas contains more than 12% oxygen (O_2) at a temperature greater than 1000 °F and is available for additional energy recovery.

There are three basic operating cycles for gas turbines. These are simple, regenerative and combined cycles. In the Stanton Unit B project, the unit will operate primarily in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The key components of a combined cycle unit (without duct firing) are shown in the figure below. The steam is then fed to a separate steam turbine, which also drives an electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA exceeds 50% on a higher heating value (HHV) basis.

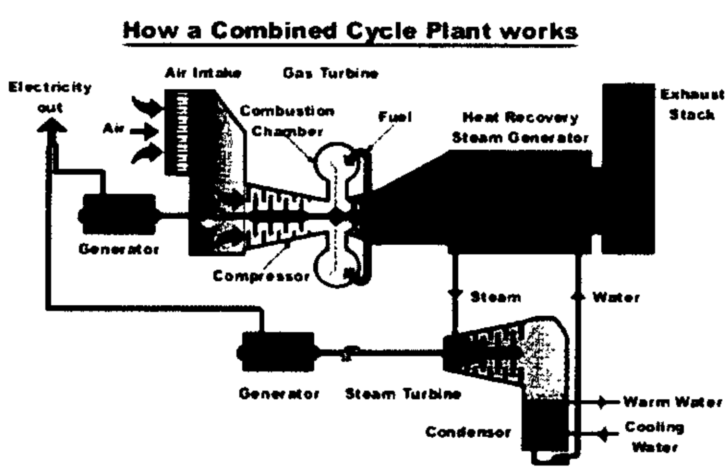


Figure 5. Components Combined Cycle Unit

The applicant has requested the following additional modes of operation.

- Fogging: Evaporative cooling (also known as "fogging") is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging is typically practiced at ambient temperatures greater than 60 °F.
- Duct firing: Gas-fired duct burners (DB) can be used in the HRSG to provide supplemental heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand that often occur at high ambient temperatures when the CTG cannot process the high air throughput rates possible at low temperatures.
- Power (steam) augmentation: Power augmentation (PA) is an infrequently used high power mode and is accomplished by returning a portion of the steam from the HRSG to the CTG to increase mass flow and power output.

Additional process information related to the combustor design, and control measures to minimize nitrogen oxides (NO_X) formation, are given in the draft BACT determination within this evaluation.

III. RULE APPLICABILITY

A. State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following rules in the F.A.C.

Table 2. Key Applicable State Regulations.

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	Air Pollution Control (Includes Adoption of Federal Regulations)
62-210	Stationary Sources – General Requirements
62-212	Stationary Sources – Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Stationary Sources – Emission Limiting Standards
62-297	Stationary Sources – Emissions Monitoring

B. Federal Regulations

This project is also subject to certain applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Table 3. Key Applicable Federal Regulations.

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 63	National Emission Standards for Hazardous Air Pollutants (NESHAP)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain – Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions
Part 96	NO_X Budget Trading Program for State Implementation Plans

C. Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as described in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant.

The Stanton Plant is a Major Stationary Source with respect to the PSD Rules because it is a fossil fuel-fired steam electric plant of more than 250 million Btu heat input and has the potential to emit 100 tons per year or more of a PSD pollutant. [Rule 62-210.200(185)(a)1., F.A.C.]

The Stanton Unit B project is a Major Modification of a Major Stationary Source if there will be a net emissions increase greater than the significant emission rate (SER) of a PSD pollutant. The SER means a rate of pollutant emissions that would equal or exceed the values described in Rule 62-210.200(185)(a)1., F.A.C. SER values relevant to the project are listed in Table 4 below.

D. Potential Emissions

For each pollutant with a net emission increase exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) as defined in Paragraph 62-210.200(39), F.A.C. to minimize emissions and conduct an ambient impact analysis as applicable.

The project will result in emissions of NO_X, SO_2, CO, $PM/PM_{10}/PM_{2.5}$, SAM, VOC and very minor emissions of lead (Pb), mercury (Hg) and other hazardous air pollutants (HAP). Table 4 summarizes the applicant's estimates of the annual emissions of key PSD pollutants in TPY from the proposed project and indicates the pollutants subject to PSD and to a determination of BACT. Included in these estimates are emissions from the CTG, the DB, the ULSD fuel oil storage tank for VOC, and the cooling tower for PM/PM_{10}.

PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRV); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. [Rule 62-212.400(5) through (9), F.A.C.]

OUC's estimates of maximum potential annual emissions from the proposed NGCC project are summarized in the following table. The emissions from the former IGCC design are included for comparison.

Table 4. Estimated Potential Annual Emissions for IGCC, NGCC versions in TPY.

Pollutant	IGCC (TPY)	NGCC (TPY)	SER (TPY)	PSD Required?
NO_X	1006 (-19)*	80	40	Yes (NGCC)
CO	654	163	100	Yes
PM/PM_{10}	189/179	110/109	25/15	Yes
SO_2	162	55	40	Yes
SAM	22.4	8	7	Yes
VOC	129	19	40	No (NGCC)
Hg	0.01	0.003	0.1	No

* Decrease of 19 TPY after consideration of concurrent reductions from existing coal-fueled Units 1 and 2. The previously proposed reductions will not be enforceable under the NGCC project.

IV. DRAFT DETERMINATION – BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

A. BACT Determination Procedure

BACT is defined in Paragraph 62-210.200 (39), FAC as follows:

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:

1. *Energy, environmental and economic impacts, and other costs;*
2. *All scientific, engineering, and technical material and other information available to the Department; and*
3. *The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.*

(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

According to Rule 62-212.400(4)(c), F.A.C., the applicant must at a minimum provide certain information in the application including:

(c) *A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;*

According to Rule 62-212.400(10), F.A.C., the Department is required to conduct a control technology review and shall not issue any permit unless it determines that:

(a) *The owner or operator of a major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan and each applicable emissions standard and standard of performance under 40 CFR Parts 60, 61, and 63.*

(b) *The owner or operator of a new major stationary source shall apply best available control technology for each PSD pollutant that the source would have the potential to emit in significant amounts.*

(c) *The owner or operator of a major modification shall apply best available control technology for each PSD pollutant which would result in a significant net emissions increase at the source. (This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.)*

(d) *The owner or operator of a phased construction project shall adhere to the procedures provided in 40 CFR 52.21(j)(4), adopted and by reference in Rule 62-204.800, F.A.C.*

B. NO_X BACT Determination

<u>NO_X Formation</u>

NO_X forms in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. It also forms by oxidation of nitrogen present in the fuel.

<u>Thermal NO_X</u>. Thermal NO_X forms in the high temperature area of the gas turbine combustor as seen on the left hand side of Figure 6.

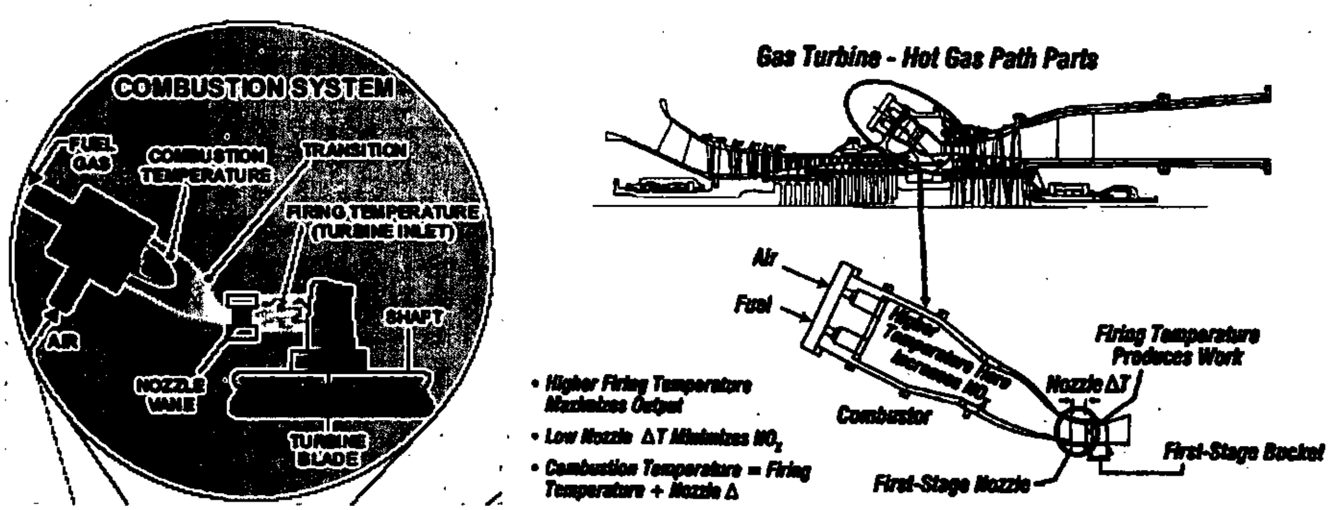


Figure 6. Relation between Combustion and Firing Temperatures and NO_X Formation

Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The relationship between flame and firing temperature, output and NO_X formation are depicted in the right side of Figure 6, which is from a GE discussion on these principles.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle.

Uncontrolled emissions can range from about 100 to over 600 parts per million by volume, dry, corrected to 15% O_2 (ppmvd @15% O_2) depending upon design. The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 from the CTG chosen for this project.

Descriptions of Available NO_X Controls

Wet Injection. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

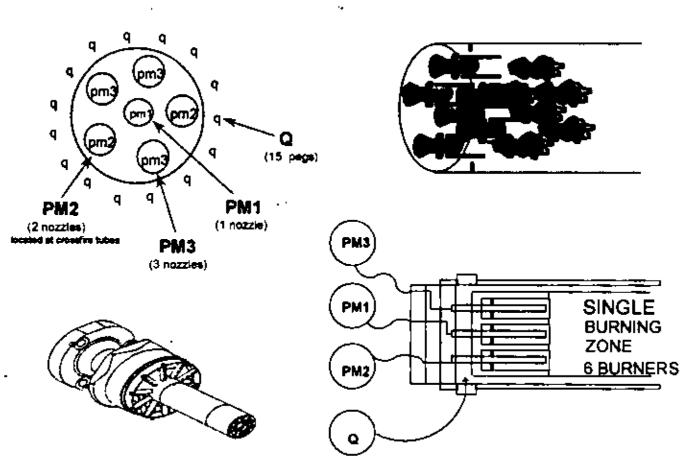
Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 85% for oil firing. These values often form the basis for further reduction to BACT limits by other techniques as discussed below.

CO and VOC emissions are relatively low for most gas turbines. However, steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls: Dry Low NO_X (DLN). The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones. The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 7.

Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

NO_X, CO, and VOC design emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 8 for a unit tuned to meet a NO_X limit of 9 ppmvd @15% O_2. Based on the design characteristics, the combustor emits NO_X at concentrations of 9 ppmvd @15% O_2 at loads between 50 and 100 percent (%) of capacity, but concentrations as high as 100 ppmvd @15% O_2 may occur at less than 50% of capacity. This suggests the need to minimize operation at low load conditions.



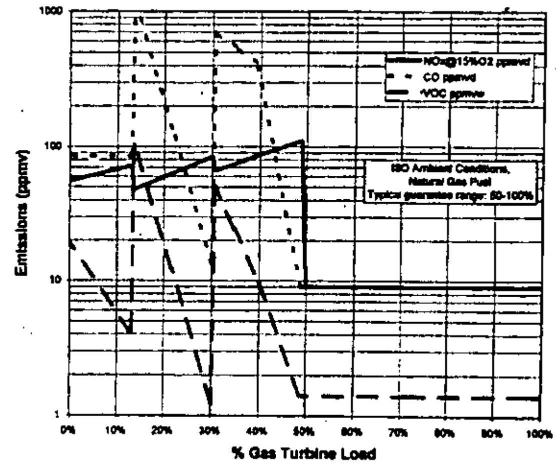
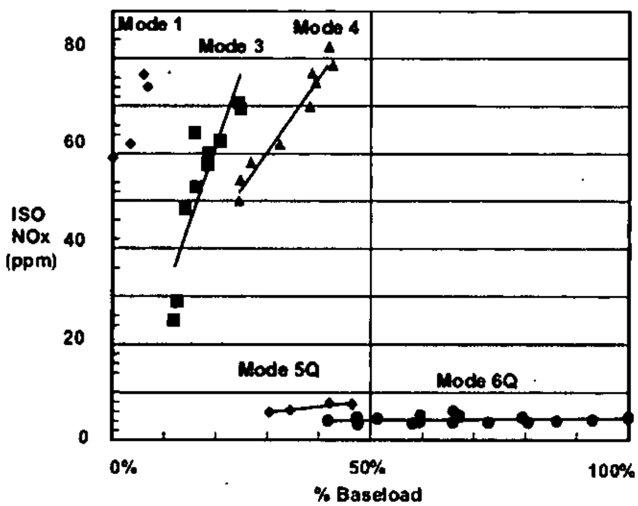


Figure 7. DLN-2.6 Fuel Nozzles. **Figure 8. Design Emissions Characteristics of DLN-2.6.**

The graphs in Figures 9 and 10 are from a GE publication and provide NO_X and CO data from actual installations or possibly test facilities. These graphs suggest that actual emissions using the DLN-2.6 technology are actually less than the design values shown in Figure 8. The data plots also suggest that there is a possibility of turndown to values somewhat less than 50% of full load without excessive emissions.



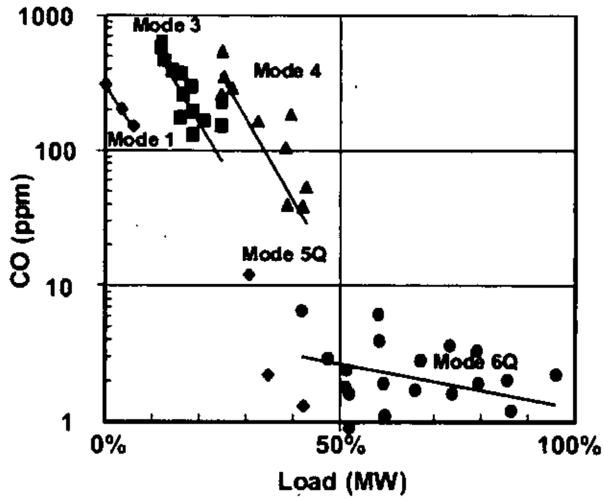


Figure 9. NO_X Emissions from DLN-2.6. **Figure 10. CO Emissions from DLN-2.6.**

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in combined cycle mode and burning natural gas at the City of Tallahassee Purdom Station Unit 8.[1]

Table 5 – City of Tallahassee Purdom Power Plant (Station Unit 8) Test Results

% of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)
70	7.2	Not Provided
80	6.1	Not Provided
90	6.6	Not Provided
100	8.7	0.85
Limit	12	25

The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd @15% O_2 of NO_X while burning natural gas although the permit limit is 12 ppmvd @15% O_2.

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[2] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 10.5 ppmvd.

Table 6 – Tampa Electric Polk Power Station Emission Test Results

% of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

The test results at the Tallahassee and TECO projects confirm NO_X, CO, and VOC emissions less than the emission characteristics published by GE in Figure 8 above. Consistent with the discussion in the previous section, conversations with plant operators indicate that the Low NO_X characteristics extend to operations somewhat less than 50 % of full load.[3] It is not certain whether low emissions under such operation are guaranteed by GE.

An important consideration in the effort to achieve low NO_X by combustion technology is that power and efficiency are sacrificed. This limitation is seen in Figure 11 below from an EPRI report.[4] Developments such as single crystal blading, aircraft compressor design, and high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by all turbine manufacturers to meet the challenges implicit in Figure 11.

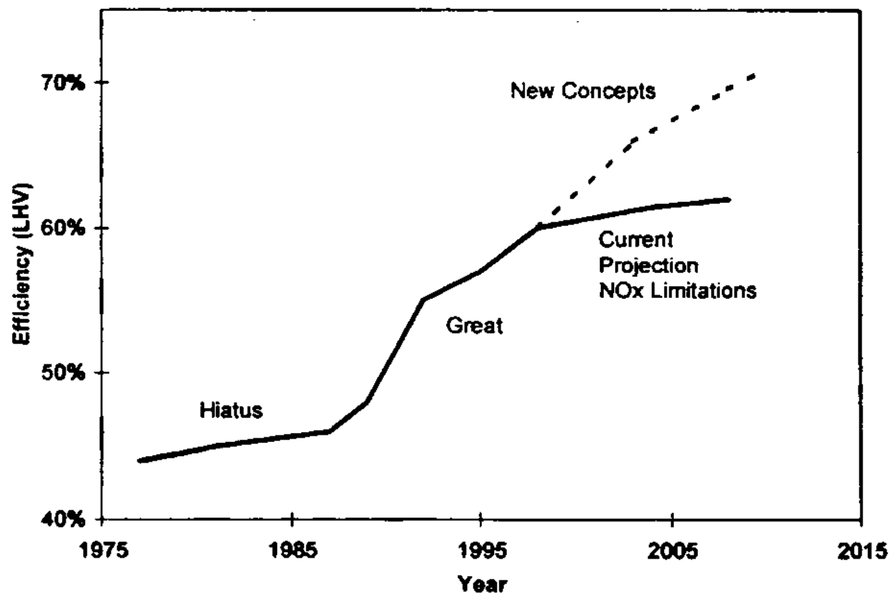


Figure 11 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned for Stanton Unit B.

Numerous 7FA units with DLN technology for NO_X control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd. This represents a reduction of approximately 95% compared with uncontrolled emissions.

A DLN technology known as Low Emissions Combustor (LEC) has been developed by Power Systems Manufacturing, LLC (PSM) for retrofitting existing units. LEC has been demonstrated to achieve NO_X emissions less than 5 ppmvd on combustion turbines as large as a GE7EA (nominal 85 MW excluding steam electrical production).[5] Low emissions of CO were also achieved. The company is working on versions suitable for the large GE 7FA and Siemens Westinghouse products.

DLN is technically possible for fuel oil, but requires a very large and expensive atomization rig and is feasible only where water is virtually unavailable. Therefore, dual fuel combustors employ wet injection to reduce NO_X emissions when firing fuel oil as discussed above.

Catalytic Combustion – XONON™. Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[6] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

Catalytica has developed a system know as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X production) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[7] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[8] By now, at least five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[9] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not feasible at this time for the OUC Stanton Unit B project.

Selective Catalytic Reduction (SCR). Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water according to the following simplified reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium (V) and titanium oxide (TiO_2) formulations and account for most installations. At high temperatures, V can contribute to ammonia oxidation forming more NO_X or forming nitrogen (N_2) without reducing NO_X according to:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \text{ and}$$

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$

For high temperature applications (hot SCR up to 1100 °F), such as large frame simple cycle turbines, special formulations or strategies are required. SCR technology has progressed considerably over the last decade with Zeolite catalyst now being used for high temperature applications. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available as evidenced by both hot and conventional installations at coal-fired plants. Such improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR (low temperature) catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas. There are numerous conventional SCR systems operating in Florida.

Figure 12 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 13 is a photograph of the existing OUC Stanton Unit A that includes two CTG. The external lines to the ammonia injection grid are visible.

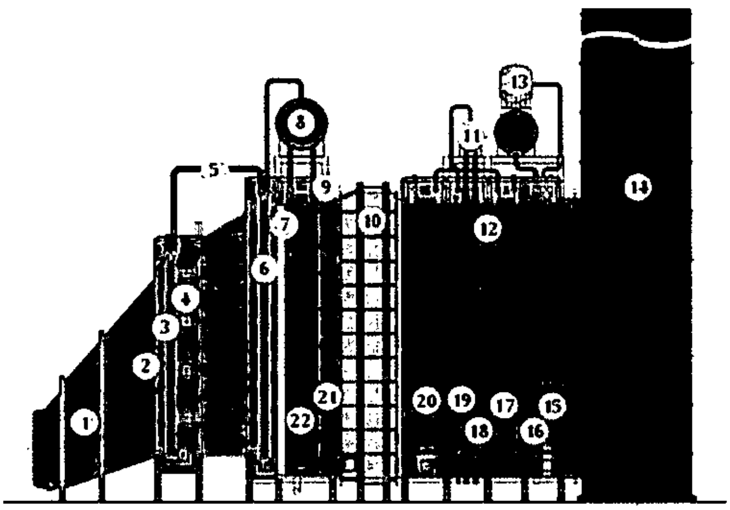


Figure 12 – Key HRSG Components (10 is SCR)

Figure 13 – OUC Stanton Unit A

If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. This is not a problem with natural gas or ultra low sulfur distillate fuel oil. Ammonia slip will gradually increase over the life of the system due to degradation of the catalyst.

The catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

Following are test results from one project that is cited by EPA Region 9 to show that NO_X emissions less than 2.0 ppmvd @15% O_2 (1-hour basis) are achieved at existing large frame combustion turbine combined cycle units using SCR.[10]

Table 7. Test Results for ABB GT-24 with SCR, ANP Blackstone Energy Co., MA[11]

% Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)	NH_3 (ppmvd)
50	1.4 – 1.7	0.5 – 0.8	0.2 – 0.4	0.08 – 0.2
75	1.5 – 1.6	< 0.1	0.2 – 0.4	0.02 – 0.06
87	1.4 – 1.7	~ 0 – 0.3	0.1	0.05 – 0.1

The units consist of two nominal 180 MW gas combustion turbine-electrical generators with an unfired HRSG, and with PA capability. It is noteworthy that the low NO_X emissions were achieved with minimal ammonia (NH_3) emissions. It would be reasonable to expect the ammonia emissions to increase over time to the guaranteed value of 2.0 ppmvd. The project employed Englehard oxidation catalyst for CO and VOC control. In the previous examples, it is noted that the GE 7FA achieved similarly low values throughout the same load range without oxidation catalyst.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle combustion turbine projects permitted with very low NO_X emissions (< 2.5/10 ppmvd for gas/oil firing). SCR results in further NO_X reduction of 60 to 95% after initial control by DLN or water injection (WI) in a combined cycle unit or total control on the order of 95 to 99%.

<u>EMx formerly SCONO$_X$</u>. This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power was the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG.

EMx systems were installed at seven sites ranging in capacity from 5 to 43 MW.[12] None was installed at a large facility.

EMx technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. EMx has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. EMx systems also oxidize emissions of CO and VOC for additional emission reductions. EMx can match the performance of SCR without ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from a natural gas reforming unit.

Table 8 contains averaged cost values for SCR with oxidation catalyst (SCR/CO) and for SCONO$_X$™ (now EMx) developed by the California Air Resources Board for their Legislature.[13] The comparison is for a 500-MW combined-cycle power plant consisting of two CTG and one STG meeting BACT requirements.

Table 8. Cost Comparison between SCR and SCONO$_X$ (now EMx) for a 500-MW Unit

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	SCONO$_X$™	SCR/CO	SCONO$_X$™
6,259,857	20,747,637	1,355,253	3,027,653

Cost figures show that the SCR/oxidation catalyst package costs less than the EMx system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

While the Department does not accept or reject the values given in Table 8, it appears that EMx is not cost-effective for the present project.

Applicant's NO$_X$ BACT Proposal

The applicant proposed that the NO$_X$ BACT for the Stanton Unit B (including the duct burners) is the use of SCR in conjunction with DLN technology on the CTG while firing natural gas, and SCR with WI while firing ultra low sulfur fuel oil. Fuel oil use will be limited to 1,000 hours per year or less.

The applicant proposed the following BACT limits for NO$_X$ on a 24-hour basis:

- Gas Firing: 2.0 ppmvd @ 15% O_2
- Oil Firing: 8.0 ppmvd @ 15% O_2

Department's Draft NO$_X$ BACT Determinations

Table 9 includes some recent BACT determinations in Florida and other states as well as some Lowest Achievable Emission Rate determinations. All used SCR. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average. The Department does not consider a 1-hour averaging time to be necessary to insure continuous low NO$_X$ levels. This provides relief from some of the small risks of occasionally exceeding the very low BACT NO$_X$ limits during an hour while not exceeding it when averaged over a day.

The Department reviewed compliance test data for the recently commissioned 1,100 MW FP&L Turkey Point Unit 5. Average NO$_X$ emissions during the tests from the four CTG that comprise Unit 5 ranged from 1.36 to 1.70 ppmvd @15% O_2 while firing natural gas (whether not the DB were used) even though their limit is 2.0 ppmvd @15% O_2 on a 24-hour basis.

The Department accepts OUC's proposal of 2.0 ppmvd @15% O_2 with an averaging period of 24-hrs, and minimization of fuel oil use to 1000 hours as BACT for this project. The limit of 2.0 ppmvd @15% O_2 represents a further reduction of 87% compared with the recently promulgated New Source Performance Standard at 40 CFR 60, Subpart KKKK.

Table 9. Recent NO_X Standards for F-Class Combined Cycle Gas Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2, Fuel	Comments
FPL Bellingham, MA	~ 545	1.5 (1-hr – 90% of time) 1.5 – 2.0 (10% of time)	2 GE 7FA (cancelled)
Towantic Energy, CT	540	2.0 NG (1-hr) 5.9 – FO	2 GE 7FA
Duke Santan, AZ	~ 900	2.0 – NG (1-hr)	3 GE 7FA & DB
Duke Morro, CA	1,200	2.0 – NG (1-hr)	4 GE 7FA & DB
ANP Blackstone, MA	~ 550	2.0 – NG (1-hr) 3.5 – NG/PA (1-hr)	2 ABB GT-24
FPL LLC Tesla, CA	1,140	2.0 - NG(3-hr)	4 GE 7FA &DBs
Milford Power, CT	~ 550	2.0 – NG (3-hr)	2 ABB GT-24
OUC Stanton B, FL	**300**	**2.0 – NG (24-hr) 8 – FO**	**1 GE 7FA & DB**
FMPA Treasure Coast, FL	300	2.0 – NG (24-hr) 8 – FO	4 GE 7FA & DB
FPL Turkey Pt, FL	1,150	2.0 – NG (24-hr) 8 – FO	4 GE 7FA & DB
Calpine OEC, PA	~ 550	2.0 – NG (3-hr) 2.5 – NG (1-hr)	2 WH 501F
Summit Vineyard, UT	560	2.0 – NG (3-hr)	2 WH501F & DB
Pacificorp Currant, UT	525	2.25 – NG (3-hr)	2 GE 7FA & DB

Notes: NG = Natural Gas DB = Duct Burner PA = Power Augmentation
FO = Fuel Oil GE = General Electric WH = Westinghouse ABB = Asea Brown Bovari

C. CO BACT Determination

CO Formation and Control Options

Carbon monoxide is a product of incomplete combustion of carbon-containing fuels such as natural gas and fuel oil. Factors adversely affecting the combustion process are low temperatures, insufficient turbulence and residence times, and inadequate amounts of excess air. Most combustion turbines incorporate good combustion practices based on high temperature, sufficient time, turbulence, and excess air to minimize emissions of CO. Additional control can be obtained by installation of oxidation catalyst, particularly on combustion turbines that do not perform well at low load conditions.

Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions are typically reported for very large combustion turbines (at least at full load operation) without use of oxidation catalyst.

Based on testing discussed in the NO_X technology section above (Tables 5 and 6), GE 7FA units achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Notably, the emissions of the GE 7FA units without oxidation catalyst matched those of the ABB units at ANP Blackstone (Table 7) that were equipped with oxidation catalyst.

Some of the more recent turbine projects within the state have been permitted with continuous emissions monitoring (CEM) requirements for CO. Continuous data from these units verify the ability of the 7FA to operate continuously with CO emission rates well below the manufacturer's guarantee. A summary of CO CEMS data recorded at TECO Bayside for 4 GE7FA units is shown in Table 10 below.

Table 10. CO CEMS Data – TECO Bayside Unit 1.

Turbine	Quarter	CO Max 24-hr Block (ppmvd)	CO Min 24-hr Block (ppmvd)	CO Quarterly Average (ppmvd)
1A	3rd Quarter 2003	4.3	0.3	0.83
1B		1.7	0	1
1C		2.1	0	0.8
1A	4th Quarter 2003	2.2	0	0.76
1B		1.9	0	1.14
1C		1.2	0	0.74

CO and VOC emissions *should be* and *are* low because of the very high combustion temperatures, excess air, and turbulence characteristic of the GE 7FA. Performance guarantees are only now "catching up" with the field experience.

GE recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units.[14] The following statement was taken from the report:

"GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN on a case-by-case basis following a detailed evaluation of the situation – thus validating its position that oxidation catalysts are not economically justified for CO emissions reduction for the GE PG7241FA DLN units while firing natural gas."

The following figure from GE's article is consistent with the data collected by the Department and supports the Department's analysis of this technical issue.

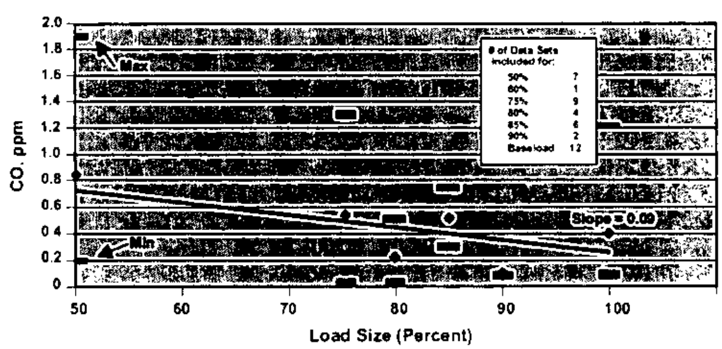


Figure 14. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

Duct Burner (DB), Fuel Oil and Power Augmentation (PA) Considerations

The proposed unit includes a HRSG equipped with supplemental duct firing. Turbine exhaust gas (TEG) is reheated with a gas-fired duct burner prior to entering the heater. Key HRSG components are shown in Figure 12 in the previous section. TEG enters the HRSG at a relatively high temperature (1,100 to 1,200 °F) and high excess air (> 12% O_2). In the design shown, some of the heat is used by a high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the TEG prior to entering a second superheater (Component 6).

Figures 15 and 16 are of an individual burner and a HRSG under construction showing horizontal duct burner elements and flow baffles.

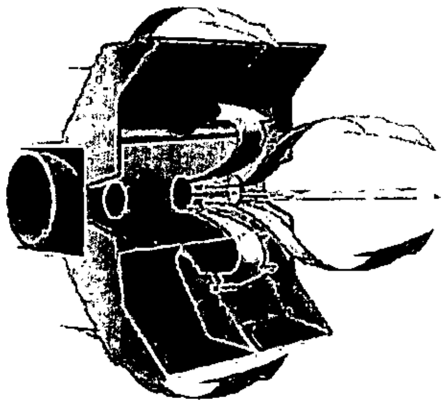


Figure 15 – Individual Burner

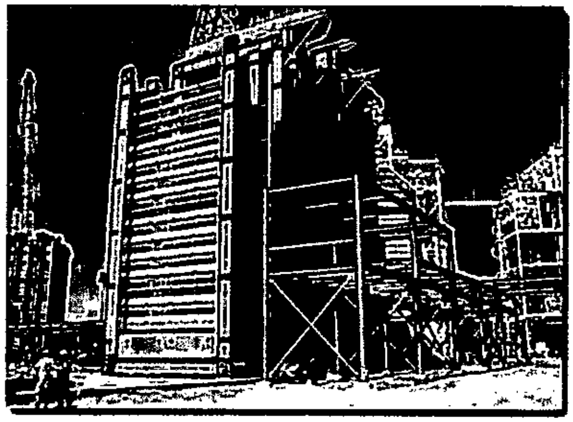


Figure 16 – Duct Burner and HRSG (Coen)

The hot TEG serves as combustion air for gas introduced into the burner array. The ignition temperature for CO is between 1,100 and 1,200 °F. All of the necessary conditions are present to minimize further CO production by the duct burner and, possibly, to incinerate CO and VOC in the TEG.

Following is a table with the results of CO and VOC testing completed on the two CTG that comprise the existing OUC Stanton Unit A. The two GE 7FA CTG are of the same type that will be installed for Stanton Unit B. Tests were conducted on each CTG while using duct burners (DB) and while practicing PA. CO emissions increase slightly when firing duct burners, but still remain very low. CO emissions were clearly greater when practicing PA.

Table 11. CO and VOC Emissions while Duct Firing – GE 7FA CTG. (ppmvd@15% O_2)

Unit (Modes)	CO	VOC
OUC Stanton A25 (CTG)	0.5	0.04
OUC Stanton A26 (CTG)	0.5	0.49
OUC Stanton A25 (CTG & DB)	1.6	0.2
OUC Stanton A26 (CTG & DB)	1.6	0.26
OUC Stanton A25 (CTG, DB & PA)	5.2	0.61
OUC Stanton A26 (CTG, DB & PA)	8.6	0.38

The Department reviewed CO and VOC data obtained during fuel oil firing at several facilities listed in Table 12 below.

Table 12. CO and VOC Emissions while firing Fuel Oil - GE 7FA CTG. (ppmvd @15% O_2)

Facility/Unit (load %)	CO	VOC
Martin Unit 8A (100%)[15]	0.6	0.4
Martin Unit 8B (100%)	0.8	0.4
TECO Polk Unit 3 (100%)	0.6	0.1
JEA Kennedy KCT-7 (100%)[16]	2.1	1.1
Stanton A25 (100%)	1.0	1.1
Stanton A26 (100%)	1.0	0.8
Reliant Osceola Unit 1 (100%)[17]	0.04	0.18
Reliant Osceola Unit 2 (100%)	0.02	0.01
Reliant Osceola Unit 3 (100%)	0.54	0.00
Oleander Power Unit 1 (100%)	1.8	< 0.7
Oleander Power Unit 2 (100%)	1.1	< 0.7
Oleander Power Unit 3 (100%)	3.8	< 0.7
Oleander Power Unit 4 (100%)	2.7	< 0.7

Measured CO and VOC emissions were also low during a test of a GE 7FA combined cycle unit (permitted in 1999) at Kissimmee Utilities Authority (KUA) while firing fuel oil and using a gas-fired DB. The results are given in the Table 13. OUC does not propose fuel oil firing while using gas-fired DB, but the results are instructive because even this special case yields low CO, VOC, and NH_3 emissions.

Table 13. Emissions while firing Fuel Oil and Duct Firing - GE 7FA CTG. (ppmvd @15% O_2)

KUA 3/Mode[18]	NO_X	CO	VOC	NH_3
CTG & DB & FO	15	1.4	0.1	1.5

Low Load Considerations

Generally speaking, the full DLN features of the DLN 2.6 operate at loads greater than 50%. For that reason, some regulatory agencies disallow operation at less than 50% load in many of the permits they issue for combustion turbines. In some cases the prohibition applies even at greater loads based on the features of the combustors.

The data in Figure 10 above suggest that there is some turndown capability while achieving low CO emissions. To maintain very low CO, the unit would need to operate in Modes 5Q or 6Q which means that five or all six fuel nozzles and quaternary pegs are in operation. The manner by which the unit is ramped up through Modes 1, 2, 4, 5Q and 6Q and then backed down to low load cannot be inferred by this diagram. Flame stability of DLN conditions at low load is complex, and will not be addressed here.

The Department obtained data from operations at JEA Brandy Branch.[19] They are summarized in the following table. For reference, a 65 MW load represents roughly 38% of full simple cycle CTG load. According to the utility, GE offers the software to tune and operate under the described conditions. A utility representative said that the unit operated in Mode 6Q during the tests.[20]

Table 14. CO Emissions during Low Load Operation at JEA Brandy Branch Unit 1

Test/Run	Load (MW)	Load (% full load)	CO (ppm)	CO (ppm @15%O_2)
1/1	65	38	9.6	8.5
1/1	65	38	9.0	8.0
1/3	65	38	9.2	8.1
2/1	65	38	12.2	10.7
2/2	65	38	12.2	10.7
2/3	65	38	11.9	10.5
3/1	65	38	12.3	10.9
3/2	65	38	11.9	10.5
3/3	65	38	12.1	10.6

Applicant's CO BACT Proposal

OUC has proposed BACT for CO as the use of good combustion controls while firing natural gas or ULSD fuel oil in accordance with the defined operating hours for each fuel. OUC proposes the following emissions limits as BACT to account for all of the scenarios discussed above.

Table 15. OUC BACT Proposal for CO Emissions from Stanton Unit B. (ppmvd@15% O_2)

Modes	CO
CTG on Natural gas	4.1
CTG on Natural Gas & DB	7.6
CTG on Natural Gas & PA (with or without DB)	14.0
CTG on Fuel Oil	8.0
CTG all Modes	8.0 (24 hours)
CTG all Modes	6.0 (12 months)

Department's Draft CO BACT Determinations

Table 16 includes some recent BACT determinations for CO and PM in Florida and other states. OUC's proposal is included for comparison. Some of the projects cited required oxidation catalyst. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average. The limit is achievable by use of oxidation catalyst.

It is clear from Tables 10, 11, 12 and 13 that CO emissions from the GE 7FA are inherently low for the normal CTG natural gas mode, the duct firing mode and the fuel oil mode even without oxidation catalyst. CO emissions were consistently less than 5 ppmvd @15% O_2. Emissions were also very low to loads equal to 50%.

Table 16. CO and PM Standards for "F-Class" Combined Cycle Units

Project Location	CO – ppmvd (@15% O_2)	PM - lb/mmBtu (or gr/dscf or lb/hr)
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	0.008
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)	0.01
Duke Morro, CA	2.0 (Ox-Cat)	0.0059 (DB off) 0.0064 (DB on)
ANP Blackstone, MA	3.0 (Ox-Cat)	0.002 (NH_3 = 2.0 ppmvd)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	0.0048 (NH_3 = 5 ppmvd) 0.0005 Cool Tower Drift
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip
OUC Stanton B, FL	**4.1 – NG (DB off, Annual Test)** **7.6 – NG (DB on, Annual Test)** **14 – NG (DB+PA)** **8.0 – FO (Annual Test)** **8.0 – 24-hr (All Modes)** **6.0 - 12-month (all modes)**	**11 lb/hr – NG (Front ½)** **14.4 lb/hr – NG (DB on)** **17.6 lb/hr – FO (Front ½)** **10% Opacity – All Modes**
FPL Turkey Pt., FL	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 14 – NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	11 lb/hr – NG (Front ½) 14.4 lb/hr – NG (DB on) 17.6 lb/hr – FO (Front ½) 10% Opacity – All Modes
FMPA TCEC, FL	8.0 NG (24-hr block) 12.0 FO (24-hr block)	38.0 lb/hr – NG (front + back ½) 52 lb/hr – FO (front + back ½)
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	0.011
Calpine OEC, PA	10 (1-hr)	0.0061
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	10% Opacity NH_3 = 5
Metcalf Energy, CA	6 - NG (100% load)	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip

Notes: NG = Natural Gas DB = Duct Burner PA = Power Augmentation
FO = Fuel Oil GE = General Electric WH = Westinghouse ABB = Asea Brown Bovari

Under the much less frequent PA mode, emissions approach 10 ppmvd @15% O_2. Similarly while operating infrequently at loads less than 50%, CO emissions can be maintained close to 10 ppmvd @15% O_2 while operating the unit with natural gas and in the 5Q or 6Q DLN modes. Some consideration can be given for the time that the unit will actually operate in those modes.

On a given day, the CTG/supplementary-fired HRSG can operate within the full spectrum of loads (40-100%), modes and fuels. The limited time during which the unit will be operated at low load can be accommodated within the limits proposed by OUC based on the data in Tables 15 presented above. While OUC has requested 1000 hours per year of ULSD fuel oil operation, they will rarely use fuel oil. Given the infrequent use of ULSD fuel oil and the fact that emissions are actually low when firing fuel oil, there would be little benefit in installing oxidation catalyst.

The Department concurs with the OUC proposal for BACT given in Table 15. BACT for CO is determined to be the 4.1 ppmvd @ 15% O_2 for natural gas firing and 7.6 ppmvd @ 15% O_2 for fuel oil firing. A continuous limit of 8.0 ppmvd @15% O_2 on a 24-hour basis will be implemented for both gas and oil firing, with or without the duct burner in operation.

An annualized limit of 6 ppmvd @15% O_2 will also be included in recognition of the preponderance of the time when the unit will be operated in the normal natural gas mode and the reality that most modes are characterized by inherently low emissions.

The BACT determination for CO is consistent with recent determinations for the FP&L West County (G-Class), FP&L Turkey Point Unit 5, Progress Energy Bartow Repowering and the FMPA Treasure Coast NGCC project.

OUC claimed that it is not cost-effective to install oxidation catalyst but did not actually submit a cost estimate to support the claim. The most recent estimate for a nearly identical project was submitted by one of the partners in the OUC Stanton Power Plant (the Florida Municipal Power Agency) for the 300 MW Treasure Coast Energy Center. That estimate was approximately $3,400 per ton removed.

A detailed cost assessment for this specific project would reveal that the cost to achieve lower CO emissions by installation of oxidation catalyst is not warranted. The cost has also been estimated by General Electric at approximately $8,000 per ton of CO removed within the previously cited report supporting the elimination of oxidation catalyst requirements for CO control on its units. While the Department does necessarily accept or reject the FMPA and GE estimates, the Department concurs that the oxidation catalyst is not cost-effective for the OUC Stanton Unit B project.

The Department reviewed compliance test data for the recently commissioned 1,100 MW FP&L Turkey Point Unit 5 that was subject to the identical limits proposed for Stanton Unit B. Average CO emissions during the tests from the four CTG that comprise Unit 5 ranged from 0.26 to 0.94 ppmvd @15% O_2 while firing natural gas (whether ULSD fuel oil or the DB were used) even though the applicable limits are 4.1 to 8.0 ppmvd @15% O_2 on a 24-hour basis. The Department believes very low CO emissions will be achieved at Stanton Unit B without oxidation catalyst and without requiring the applicant to obtain even lower emission guarantees from the suppliers.

D. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2. Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution to the market.

For this project the applicant has proposed as BACT the use of ULSD fuel oil (0.0015% sulfur) and clean natural gas with a sulfur fuel specification less than 2 grains of sulfur per 100 standard cubic feet of natural gas (≤ 2 gr/100 SCF). For reference, the sulfur specification of the natural gas is approximately equal to 0.006% (by weight).

OUC estimated 55 TPY of SO_2 and 8 TPY of SAM from Stanton Unit B. This equates to 412 and 40 TPY for SO_2 and SAM respectively from the two combined cycle units. Realistically, annual emissions will be approximately one-fourth of the estimated values because the sulfur concentration in the pipeline gas is typically closer to 0.5 gr/100 SCF than to 2 gr/100 SCF. The concentration of sulfur in the ULSD fuel oil has been reported at approximately half of the specification.

At such low sulfur concentrations, annual emissions of both pollutants will likely be less than the respective PSD thresholds of 40 and 7 TPY of SO_2 and SAM respectively. The Department accepts OUC's BACT proposal for SO_2 and SAM. This approach is consistent with other recently permitted projects.

E. Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT Determination and NH_3 Control

$PM/PM_{10}/PM_{2.5}$ Formation and Control Options

PM, PM_{10} and $PM_{2.5}$ will be emitted from the CTG due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Natural gas and ULSD will be efficiently combusted at high temperature in the CTG and will be the only fuels fired in the proposed unit. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The ULSD fuel oil to be combusted contains a minimal amount of ash and will be limited to less than 1000 hours per year making any conceivable add-on control technique for $PM/PM_{10}/PM_{2.5}$ either unnecessary or impractical.

Other $PM/PM_{10}/PM_{2.5}$ Considerations

Ammonia Slip and Ammonium Salts Formation: Emissions of NO_X, SO_2, and SAM are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. These constituents form the fine PM that comprises $PM_{2.5}$. $PM_{10}/PM_{2.5}$ emissions can be increased due to the formation of these ammonium salts prior to exiting the stack or in the environment and contribute to regional haze. The BACT process limits the nitrate and sulfate formation potential of the CTG exhaust. It is important to limit ammonia emissions (known as slip) originating from the SCR NO_X control technology. Elevated levels of ammonia slip can also be an indication of a degrading catalyst. The Department proposes an ammonia limit of 5 ppmvd @ 15% O_2.

Cooling Tower PM Emissions: Small amounts of water entrained in the air passing through a wet cooling tower can be carried out of the tower and are known as "drift" droplets. Because the droplets contain impurities from the cooling water, the particulate matter constituent of the drift droplets may be classified as an emission[21]. The amount of particulate matter that may be emitted is based on the solids loading in the re-circulating water.

The applicant's proposal includes a 6-cell, 56,000 gallons per minute (gpm) mechanical draft cooling tower with drift eliminators with a design drift rate of 0.0005% of design water flow. The height of each cell will be 50 feet (nominal) with an exit diameter of 33.5 feet (nominal). OUC estimates annual PM and PM_{10} emissions from the cooling tower to be 2.3 TPY and 0.94 TPY respectively.

<u>Applicant's PM/PM_{10}/$PM_{2.5}$ Proposal</u>

The applicant determined that the PM/PM_{10}/$PM_{2.5}$ BACT for proposed Stanton Unit B is good combustion controls and the use of natural gas and ULSD fuel oil.

<u>Department's Draft PM/PM_{10}/$PM_{2.5}$ BACT Determinations</u>

The following conditions are established as the draft BACT standards.

- The gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 gr S/100 SCF of natural gas. The duct burners are limited to firing only natural gas meeting this specification. The gas turbine may fire ULSD fuel oil as a restricted alternate fuel (≤ 1,000 hours per year), which shall contain no more than 0.0015% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.
- Ammonia emissions (slip) shall not exceed 5 ppmvd.
- The cooling tower shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%.

The Department notes that the described measures minimize emissions and formation of fine particulate matter classified as $PM_{2.5}$. The described strategy directly reduces PM emissions as well as formation of ammoniated PM. The NO_X, SO_2 and NH_3 control strategies minimize emissions of precursors known to contribute to formation of $PM_{2.5}$ in the environment.

F. New Source Performance Standards Applicable to Gas Turbines and Duct Burners

Stationary gas turbines are subject to the recent federal New Source Performance Standards in Subpart KKKK of 40 CFR 60. These requirements result in the following standards for the proposed CTG including the DB located in the HRSG. The limits are:

- NO_X (gas) ≤ 15 ppm @ 15% O_2 or 0. 43 lb/MWh (4-hr average);
- NO_X (oil) ≤ 42 ppm @ 15% O_2 or 1.3 lb/MWh (30 operating day average); and
- SO_2 ≤ 0.90 lb/MWh or ≤ 0.060 lb SO_2/MMBtu

Purchase contracts or tariff sheets can be used in place of fuel sulfur content monitoring by demonstrating sulfur content of no more than 0.05% by weight fuel oil or 20 gr/100 SCF of natural gas. The Department's BACT determinations are significantly more stringent than the requirements of 40 CFR 60, Subpart KKKK. The short term nature of the NO_X limit under Subpart KKKK will necessitate an additional limit in the permit. Subpart KKKK also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations.

G. Summary of Department Draft BACT Determination

Emissions from the gas turbine shall not exceed the values given in Table 17.

Table 17. Draft BACT Determination – Curtis H. Stanton Energy Center Unit 1

Pollutant	Fuel	Method of Operation	Initial and Annual Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CTG)	8.0	36.7	8.0, 24-hr
	Gas	CTG Normal	4.1	15.9	
		CTG & Duct Burner (DB)	7.6	37.2	
		CTG Low Load	NA	NA	
		CTG & PA with or w/o DB	NA	NA	14.0, 24-hr
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X [b]	Oil	CTG	8.0	60.3	8.0, 24-hr
	Gas	CTG Normal	2.0	12.7	2.0, 24-hr
		CTG & DB	2.0	16.1	
		CTG & PA with or w/o DB	NA	NA	
$PM/PM_{10}/PM_{2.5}$ [c]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
Ammonia [e]	Oil/Gas	CTG, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the PA mode and all other modes based on the hours of operation for each mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

f. The mass emission rate standards are based on a turbine inlet condition of 70 °F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

V. PERIODS OF EXCESS EMISSIONS

A. Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NO_X emissions.

B. Alternate Standards and Excess Emissions Allowed (NO_X, CO and Opacity)

In accordance with Rule 62-210.700, F.A.C., "Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

Operation of the GE 7FA CTG in lean premix mode is achieved by at least 50% of base load conditions. Startup when the HRSG or STG is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and STG components is accomplished by operating the gas turbines for extended periods at reduced loads (<10%), which results in higher emissions. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for the CTG/HRSG system.

- Excess NO_X and CO emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized.
- For oil-to-gas fuel switching excess NO_X and CO emissions shall not exceed 1 hour in any 24-hour period.
- Excess NO_X and CO emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.
- For warm startup, up to four hours of excess NO_X and CO emissions are allowed. "Warm startup" is defined as a startup following a shutdown lasting between 8 and 48 hours.
- For cold startup to combined cycle operation, up to six hours of excess NO_X and CO emissions are allowed. "Cold startup" is defined as a startup following a shutdown lasting at least 48 hours.
- For shutdown, up to three hours of excess NO_X and CO emissions are allowed.

- For startup, ammonia injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

While NO_X emissions during warm and cold startups are greater than during full load steady-state operation, such startups are generally infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation. The draft permit will also require the installation of a damper to reduce heat loss during combined cycle shutdowns to minimize the number of combined cycle cold startups.

DLN Tuning

DLN combustion systems require initial and periodic "tuning" to account for changing ambient conditions, changes in fuels and normal wear and tear on the unit. Tuning involves optimizing NO_X and CO emissions, and extends the life of the unit components. A major tuning session would typically occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar event. Excess emissions of NO_X, CO, and opacity are allowed during DLN tuning sessions provided the proper notification is provided to the Compliance Authority. Notification two weeks prior to tuning will be required.

Combined Cycle Operation with Dump Condenser

Under the rare circumstance that the STG is off line for some reason, it is possible that the CTG/HRSG systems would operate without producing any steam generated power. Instead, steam would be delivered to a dump condenser. Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection.

VI. AIR QUALITY IMPACT ANALYSIS

A. Introduction

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2 and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for SAM. VOC and NO_X are ozone precursors and any net increase of 100 TPY would (in contrast to the present project) require an ambient impact analysis including the evaluation or collection of preconstruction ambient air quality data.

B. Major Stationary Sources in Orange County

The current largest stationary sources of air pollution in Orange County are listed below. The information is from annual operating reports submitted to the Department from 2006. The emissions of NO_X and SO_2 from Stanton Unit B will be minimal (< 1%) compared with emissions from the rest of the plant. The emissions will also be less than the year-to-year variation of present plant SO_2 and NO_X emissions.

Table 18. Largest Sources of SO_2 in Orange County

Owner	Site Name	Tons per year
Orlando Utilities Commission	Stanton Energy Center (Existing)	8193
Orlando Utilities Commission	**Stanton Unit B (Proposed)**	**55**
Middlesex Asphalt LLC	Orange County Plant	13
Ranger Construction Industries	Ranger Construction–Winter Garden	10

Table 19. Largest Sources of PM_{10} in Orange County

Owner	Site Name	Tons per year
Orlando Utilities Commission	Stanton Energy Center (Existing)	396
Orlando Utilities Commission	**Stanton Unit B (Proposed)**	**109**
Orlando Cogen Limited, L.P.	Orlando Cogen Limited, L.P.	31
Walt Disney World Company	Walt Disney World Resort	13

Table 20. Largest Sources of CO in Orange County

Owner	Site Name	Tons per year
Orlando Utilities Commission	Stanton Energy Center (Existing)	716
Orlando Utilities Commission	**Stanton Unit B (Proposed)**	**163**
Florida Gas Transmission Co.	FGTC Station 18	71
Kinder Morgan Energy Partners	Central Florida Pipeline	49

Table 21. Largest Sources of NO_X in Orange County

Owner	Site Name	Tons per year
Orlando Utilities Commission	Stanton Energy Center (Existing)	8823
FL Gas Transmission Co.	FGTC Station 18	548
Walt Disney World Company	Walt Disney World Resort	236
Orlando Cogen Limited, L.P.	Orlando Cogen Limited, L.P.	198
Orlando Utilities Commission	**Stanton Unit B (Proposed)**	**80**

C. Air Quality and Monitoring in the Orange County

The Orange County Local Program operates twelve criteria pollutant monitors at five sites measuring PM_{10}, $PM_{2.5}$, ozone (O_3), CO, nitrogen dioxide (NO_2) and SO_2. The 2007 monitoring network is shown in the figure below.

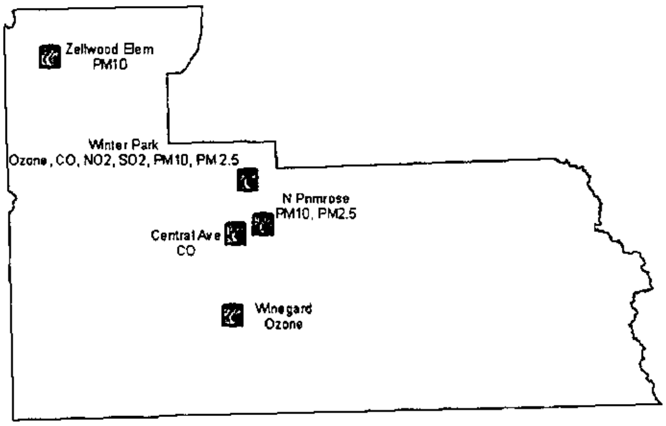


Figure 17. Orange County Ambient Air Monitoring Network

The results of monitoring conducted during 2006 are summarized in the following table. All of the stations were in attainment with the corresponding ambient air quality standards (AAQS).

Table 22. Ambient Air Quality in Orange County Nearest to Project Site (2006)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	N Primrose	24-hour	42	38		150[a]	$\mu g/m^3$
		Annual			21	50[b]	$\mu g/m^3$
$PM_{2.5}$	Winter Park	24-hour	36	29		35[c]	$\mu g/m^3$
		Annual			11	15[d]	$\mu g/m^3$
SO_2	Winter Park	3-hour	10	9		500[e]	ppb
		24-hour	3	3		100[e]	ppb
		Annual			1	20[b]	ppb
NO_2	Winter Park	Annual			9	53[b]	ppb
CO	Central Avenue	1-hour	3	2		35[e]	ppm
		8-hour	2	2		9[e]	ppm
Ozone	Winegard	1-hour	0.102	0.089		0.12[f]	ppm
		8-hour	0.083	0.082		0.08[g]	ppm
		8-hour	2007 3-yr attainment		81	85	ppb

a. Not to be exceeded on more than an average of one day per year over a three-year period
b. Arithmetic mean
c. Three year average of the 98th percentile of 24-hour concentrations
d. Three year average of the weighted annual mean
e. Not to be exceeded more than once per year
f. Not to be exceeded on more than an average of one day per year over a three-year period.
g. Three year average of the 4th highest daily maximum 8-hr average over each year

On March 12, 2008 the U.S. Environmental Protection Agency announced that it will reduce the 8-hour ozone standard listed above from 85 parts per billion (ppb) to 75 ppb. Upon redesignation and classification, possibly in 2010, the areas shown in the following figure (including Orange County) may no longer be in attainment with the applicable ozone AAQS.

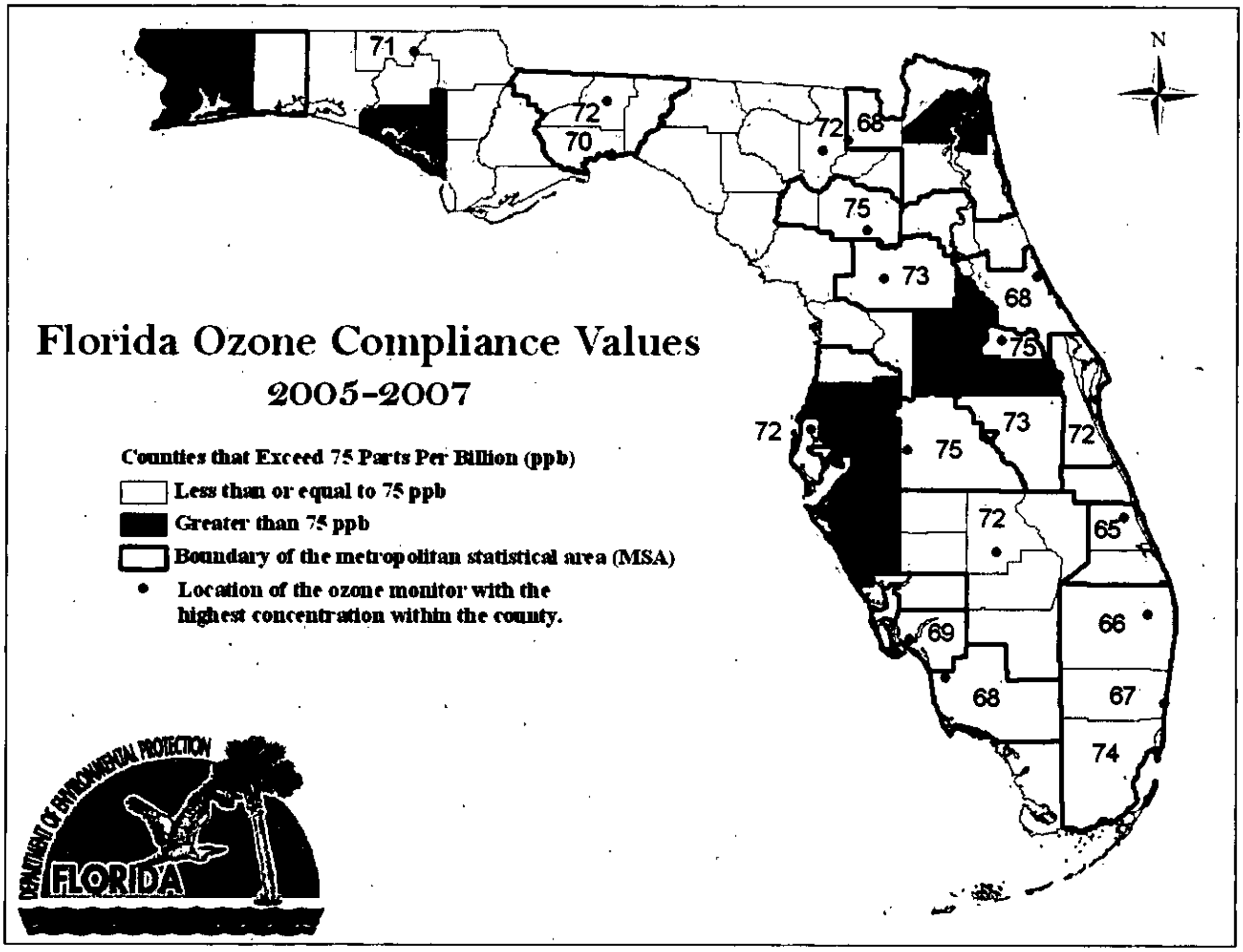


Figure 18. Map indicating Areas Registering an ozone Value Greater than 75 ppb.

Some of the recent trends in ambient air quality in Orange County are depicted in the following figures.[22]

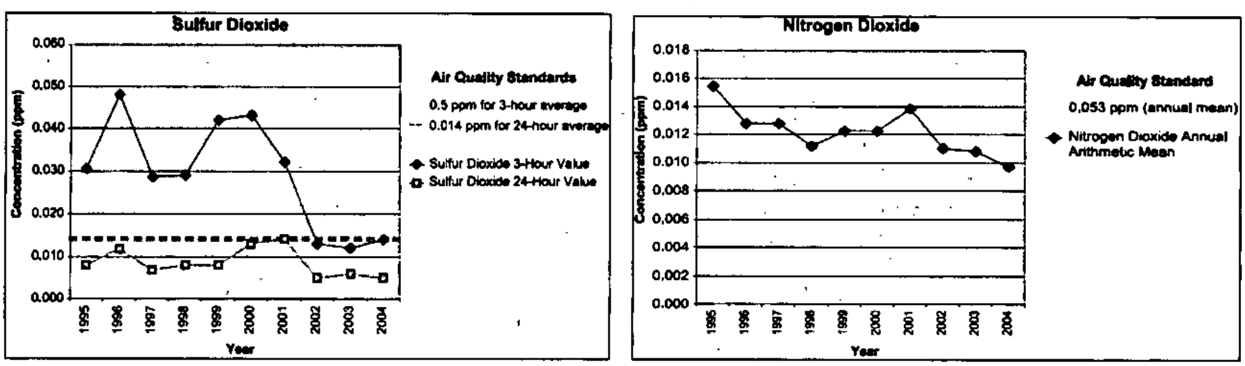


Figure 19. SO_2 and NO_2 Trends in Orange County Florida. 1995-2004.

A large reduction in maximum 3-hour and 24-hour SO_2 trends is clear. The main reason for the reduction is FPL's natural gas repowering project at the residual fuel oil-fired Sanford Power Plant. The benefits of the repowering between 2000 and 2002 overwhelmed the startup of coal-fueled Stanton Unit 2 (with a flue gas desulfurization scrubber) that occurred in 1997. The net reduction in combined SO_2 emissions from the two plants is on the order of 20,000 tons per year.

A similar trend is noticeable in NO_2, (NO_X indicator pollutant). This again suggests beneficial effects of the Sanford Power Plant repowering project and NO_X emissions reductions even with the Stanton Unit 2 project (that incorporated an SCR system).

A trend towards lower ozone is also seen in the following figure that is partially explained by the reduction in precursors (NO_X).

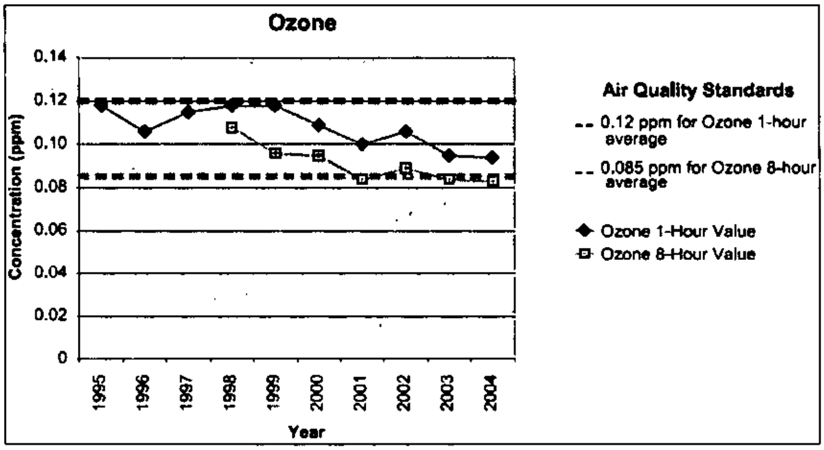


Figure 20. Ozone (O_3) Trends in Orange County Florida. 1995-2004.

Ozone trends also reflect VOC emissions, contributions from transportation emissions, the climatological cycles and the presence of meteorological conditions such as hot ambient temperature, solar insolation, high pressure, and relatively low wind speed that contribute to ozone formation and persistence. The 2007 value of 81 ppb (0.081 ppm) demonstrates a leveling of the trend towards progressively declining ozone values seen between 1998 and 2004. The large regional NO_X decreases expected due to the Clean Air Interstate Rule (CAIR) may yet help reestablish the downward trend in order to meet the new EPA standard of 75 ppb.

D. Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SIL) are defined for PM/PM_{10}, CO, NO_X and SO_2. A significant impact analysis is performed on each of these pollutants to determine if a project can even cause an increase in ground level concentration greater than the SIL for each pollutant.

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SIL for the PSD Class I Chassahowitzka National Wildlife Refuge (CNWR) and the PSD Class II Area (everywhere except the Class I area).

For the Class II analysis a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50-meter intervals around the facility fence line.

The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart starting at the property line and extending to 3 kilometers. Beyond 3 kilometers, Cartesian receptors with a spacing of 250 meters were used out to 6 kilometers from the facility. From 6 to 15 kilometers, Cartesian receptors with a spacing of 500 meters were used.

According to the application, 113 receptors, identified by the National Park Service, were used for the CNWR Class I analysis.

If this modeling at worst-load conditions shows ground-level increases less than the SIL, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SIL, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS and PSD increments.

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SIL for the Class II area. These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 23. Maximum Projected Air Quality Impacts from OUC Stanton Unit B Project for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Baseline (2006) Concentrations ($\mu g/m^3$)	Ambient Air Standards ($\mu g/m^3$)	Significant Impact?
SO_2	Annual	0.1	1	~3	60	No
	24-Hour	0.5	5	~8	260	No
	3-Hour	1.4	25	~26	1300	No
PM_{10}	Annual	0.1	1	~21	50	No
	24-Hour	1.5	5	~42	150	No
CO	8-Hour	5	500	~2300	10,000	No
	1-Hour	4	2000	~3450	40,000	No
NO_2	Annual	0.3	1	~17	100	No

It is clear that maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the CNWR located about 144 km to the northwest of the project site. Maximum air quality impacts from the proposed project are summarized in the following table. The results of the initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from SO_2, PM_{10}, and NO_2 are less than the applicable SIL for the Class I area. Therefore, no further detailed modeling efforts are required.

Table 24. Maximum Air Quality Impacts from the OUC Stanton Unit B Project for comparison to the PSD Class I SIL at CNWR

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (μg/m^3)	Class I Significant Impact Level (μg/m^3)	Significant Impact?
PM_{10}	Annual	0.001	0.2	No
	24-hour	0.03	0.3	No
NO_2	Annual	0.001	0.1	No
SO_2	Annual	0.0004	0.1	No
	24-hour	0.01	0.2	No
	3-hour	0.02	1	No

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

Table 25. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	1.5	10	~42	No
NO_2	Annual	0.2	14	~17	No
SO_2	24-hour	1	13	~8	No
CO	8-hour	5	575	~2300	No

Projects with VOC or NO_X emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including sophisticated modeling and gathering of preconstruction ambient air quality data. The proposed project predicts worst case emissions to be less than 100 tons per year for these ozone precursors and thus is not subject to an ambient impact analysis for ozone.

Based on the preceding discussions, the only additional detailed air quality analyses required by the PSD regulations for this project is the following:

- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Foregoing Air Quality Analysis

PSD Class II Area: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. AERMOD was approved by the EPA in November 2005. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

The AERMET meteorological data used for this analysis consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service at Orlando International Airport and Tampa/Ruskin respectively. The 5-year period of meteorological data was from 1999 through 2003. These airport stations were selected for use in the study because they are most representative of the project site.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

PSD Class I Area: The EPA regulatory version of the California Puff (CALPUFF) dispersion modeling system was used to evaluate the pollutant emissions from the proposed project in the Class I CNWR beyond 50 km from the proposed project. The meteorological or (CALMET) dataset was processed using prognostic model data (MM4 and MM5) from 2001, 2002 and 2003.

CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources.

The CALPUFF model has the capability to treat time-varying sources, is suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanism.

E. ADDITIONAL IMPACTS ANALYSIS

Impact on Soils, Vegetation, and Wildlife:

The NGCC version of Stanton B replaces the previously approved IGCC version. In terms of gross emissions, those from the NGCC project will be less than the previously planned IGCC unit. The impact of the NGCC project on soils, vegetation and wildlife will likely be less than the previously projected non-adverse impact of the IGCC unit.

In contrast to the NGCC project, the IGCC project included a cap on NO_X from the two coal-fueled units (Stanton Units 1 and 2) and a permanent reduction of approximately 1,000 TPY of NO_X that effectively offset the similar increase permitted for the IGCC project.

As a practical matter, it is likely that significant NO_X emission reductions will still be realized from Units 1 and 2 given the recent projects actually under construction to install improved low NO_X burners and overfire air (OFA) on the two units. Therefore, it may be fair to compare the 80 TPY increase from the NGCC with the previously projected NO_X emission level of 1006 TPY from the IGCC without the offsets from Units 1 and 2.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I area. This includes the analysis of sulfur and nitrogen deposition. The CALPUFF model is also used in this analysis to produce quantitative impacts. The results of the analysis show that nitrogen and sulfur deposition rates are less than the significant impact levels (0.01 kg/ha/yr) determined by the National Park Service.

The Department concludes that there will be minimal air impacts, if any, on flora, fauna and soils.

Impact on Visibility:

The applicant submitted a regional haze analysis for the CNWR. The analysis included modeling from the CALPUFF model. The National Park Service threshold for visibility percent change in extinction is 5%. The modeling results concluded that the new unit will not contribute to an adverse impact.

Minimization of acid rain and ozone precursors also minimizes fine particulate emissions, fine particulate formation in the environment and thus regional visibility effects.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, population growth in the area of the proposed project, Orange County, has doubled from 1980 to 2000. Housing units have also doubled in the same time period. The Orlando population as of 2003 was 1,755,000. Most of the growth has been tourism-dominated. This tourism-dominated growth has lead to an increase in mobile source activity in terms of vehicle miles traveled. However, increases in air pollution due to mobile sources have been counteracted by cleaner fuels and technological advances.

The beginning of the decade has shown that growth in the area has slowed. New power plants in the area have included good air pollution control equipment and the large existing residual oil fired plant has been repowered with natural gas.

VII. CONCLUSION

The Department has reasonable assurance that the proposed Stanton Unit B project will comply with the Department's regulations and has made a preliminary decision to issue a permit under the Rules for the Prevention of Significant Deterioration. The Department has reviewed and concurs with the applicant's BACT proposals.

Based on the ambient air quality review, the Department concludes that the project will neither cause nor contribute to a violation of ambient air quality standards or increments. Furthermore, there will not be significant impacts on soils, wildlife or vegetation.

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PERMITTEE

Orlando Utilities Commission (OUC)
Post Office Box 3193
Orlando, Florida 32802

Authorized Representative:
Ms. Denise M. Stalls,
Vice President, Environmental Affairs

DEP File No. 0950137-020-AC
Permit No. PSD-FL-373A
Curtis H. Stanton Energy Center
Combined Cycle Unit B
Orange County, Florida
Expires: December 31, 2011

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 300 megawatts (MW) natural gas-fueled combined cycle (NGCC) unit (Unit B) at the existing OUC Curtis H. Stanton Energy Center. The project consists of: a nominal 150 MW General Electric 7FA combustion turbine-electrical generator, a duct fired heat recovery steam generator, a nominal 150 MW steam-electrical generator, a nominal 205-foot stack, a mechanical draft cooling tower with drift eliminators and a nominal 1,000,000 gallon fuel oil storage tank.

This permitting action also rescinds Permit No. PSD-373 (DEP File No. 0950137-010-AC) that previously authorized construction of a nominal 285 MW integrated coal gasification and combined cycle (IGCC) unit and that established a limitation on nitrogen oxides (NO_X) emissions of 8,300 tons per year on a 12-month rolling basis beginning the first month of first fire of Unit B from existing coal fired Units 1 and 2.

The facility is located at 5100 South Alafaya Trail, Orlando in Orange County. The UTM coordinates for this site are 483.6 km East and 3151.1 North.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations (CFR). The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

Joseph Kahn, Director
Division of Air Resource Management

(Date)

SECTION I - GENERAL INFORMATION

FACILITY AND PROJECT DESCRIPTION

The existing facility consists of two 468 MW fossil fuel fired steam electric generating units (Units 1 and 2), and one 640 MW NGCC unit (Unit A). There are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash.

A previously permitted, but not constructed, nominal 285 MW IGCC unit (Unit B) will be replaced by the proposed project. In lieu of the IGCC unit, Stanton Unit B will be comprised of a "one-on-one" F-Class NGCC unit and associated auxiliary equipment. The project now consists of: a nominal 150 MW natural gas-fueled General Electric 7FA combustion turbine-electrical generator (CTG), a supplementary-fired heat recovery steam generator (HRSG) with duct burner, a nominal 150 MW steam-electrical generator (STG), a nominal 205-foot stack, a mechanical draft cooling tower with drift eliminators and a nominal 1,000,000 gallon tank to store backup ultralow sulfur diesel (ULSD) fuel oil. The duct burner (DB) has a nominal rating of 450 million Btu per hour (mmBtu/hr) heat input.

EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units:

EU ID NO.	EMISSION UNIT DESCRIPTION
030	Unit B is comprised of: a nominal 150 MW natural gas-fueled General Electric 7FA CTG equipped with evaporative inlet air cooling and power (steam) augmentation equipment; a supplementary-fired HRSG with a nominal 500 mmBtu/hr DB; a HRSG stack; and a nominal 150 MW STG.
031	A six-cell mechanical cooling tower with individual exhaust fans and drift eliminators.
032	One nominal 1,000,000 gallons ULSD fuel oil storage tank.

REGULATORY CLASSIFICATION

The facility operates existing units subject to the Acid Rain provisions of Title IV of the Clean Air Act (CAA).

The facility is a Title V major source of air pollution in accordance with Chapter 213, Florida Administrative Code (F.A.C.).

The facility is a major Prevention of Significant Deterioration (PSD) stationary source in accordance with Rule 62-212.400, F.A.C. Unit B is subject to the PSD rules including a determination of best available control technology (BACT).

The facility operates units subject to the Standards of Performance for New Stationary Sources pursuant to 40 CFR Part 60. Unit B is subject to 40CFR60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also covers duct burners that are incorporated into combined cycle projects.

The existing facility is a major source of hazardous air pollutants (HAP). Unit B is potentially subject to 40 CFR63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired combustion turbines such as planned for this project.

The facility is subject to the Federal Clean Air Interstate Rule (CAIR) in accordance with the Final Department Rules issued pursuant to CAIR as implemented by the Department in Rule 62-296.470, F.A.C.

The facility operates units that were certified under the Florida Power Plant Siting Act, 403.501-518, F.S.

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft air construction permit; and the Department's Technical Evaluation and Preliminary Determination.

1. Permitting Authority: The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Department. The mailing address for the Bureau of Air Regulation is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Central District Office. The mailing address and phone number of the Central District Office are: Department of Environmental Protection, Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando Florida 32803-3767. Telephone: (407)894-7555. Fax: (407)897-5963.
3. Appendices: The following Appendices are attached as part of this permit: Appendices A, BD, GC (General Conditions), KKKK, SC, XS and YYYY.
4. 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, 62-214, 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.
5. 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.]
6. Modifications: No emissions unit shall be constructed or 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.]
7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of BACT for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]
8. Title V Permit: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the required work and commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Bureau of Air Regulation with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. Combined Cycle Unit B (EU 030)

This section of the permit addresses the following emissions unit.

EU ID NO.	EMISSION UNIT DESCRIPTION
030	Unit B is comprised of: a nominal 150 MW natural gas-fueled General Electric 7FA CTG equipped with evaporative inlet air cooling and power (steam) augmentation equipment; a supplementary-fired HRSG with a nominal 450 mmBtu/hr DB; a HRSG stack; and a nominal 150 MW STG.

Applicable Standards and Regulations

1. BACT Determinations: The emission unit addressed in this section is subject to a BACT determination for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the NSPS for Subpart KKKK. Some separate reporting and monitoring may be required by these subparts.

   (a) Subpart A, General Provisions, including:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) Subpart KKKK, Standards of Performance for Stationary Gas Turbines: These provisions include standards for combustion gas turbines and duct burners.

Equipment

3. CTG: The permittee is authorized to install, tune, operate, and maintain one natural gas-fueled GE Model 7FA CTG with a nominal generating capacity of 150 MW. The CTG will be equipped with Dry Low NO_x (DLN) combustors, an inlet air filtration system with evaporative coolers, power (steam) augmentation capability and the capability to fire ULSD fuel oil. The unit shall be equipped with the Speedtronic™ Mark VI (or more recent version) automated gas turbine control system. [Application; Design]

4. HRSG: The permittee is authorized to install, operate, and maintain one HRSG with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator with a nominal generating capacity of 150 MW. The HRSG will be equipped with supplemental gas-fired DB having a nominal heat input rate of 450 mmBtu (HHV). [Application]

Control Technology

5. DLN Combustion: The permittee shall operate and maintain the GE DLN 2.6 combustion system (or better) to control NO_X emissions from the CTG when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

6. Wet Injection: The permittee shall install, operate, and maintain a wet injection system (water or steam) to reduce NO_X emissions from the CTG when ULSD distillate fuel oil is fired. Prior to the initial emissions performance tests required for the gas turbine, the wet injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

7. Selective Catalytic Reduction (SCR) System: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from the gas turbine when firing either natural gas or ULSD distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

   Ammonia Storage: In accordance with 40 CFR 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

   [Design; Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

8. Capacity – CTG: The nominal heat input rating excluding steam for power augmentation of the CTG is 1,765 mmBtu per hour when firing natural gas and 1,935 mmBtu per hour when firing ULSD fuel oil based on a compressor inlet air temperature of 70° F, the higher heating value (HHV) of each fuel, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.
   [Rule 62-210.200(Definitions – Potential to Emit), F.A.C.]

9. Capacity - DB: The nominal heat input rating of the DB located within the HRSG is 450 mmBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the DB.
   [Rule 62-210.200(Definitions – Potential to Emit), F.A.C.]

10. Hours of Operation: The gas turbine may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified in separate conditions.
    [Rules 62-210.200(Definitions - PTE) and 62-212.400 (BACT), F.A.C.]

11. Authorized Fuels: The CTG turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, the CTG may fire ULSD distillate fuel oil containing no more than 0.0015% sulfur by weight. The CTG shall fire no more than 1000 hours of ULSD fuel oil, regardless of mode, during any calendar year.
    [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

12. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbine may operate under the following methods of operation.

    a. *Combined Cycle Operation*: The CTG/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

b. *Pseudo Simple Cycle Operation*: The CTG/HRSG system may operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser. This is not considered a separate mode of operation with respect to emission limits (i.e. emission limits of combined cycle operation still apply).

c. *Inlet Fogging*: Evaporative cooling (also known as "fogging") is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging will be implemented at ambient temperatures of 60° F or higher.

d. *Power Augmentation (PA)*: PA provides additional direct, shaft-driven electrical power by increasing the mass flow rate through the compressor by the injection of steam. Steam for PA is taken from the HRSG and is introduced into the gas turbine compressor discharge, thus increasing the power produced by the expander portion of the turbine

e. *DB Firing*: The HRSG system may fire natural gas in the DB to provide additional steam-generated electrical power.

[Application; Rules 62-210.200 (PTE) and 62-212.400 (BACT), F.A.C.]

Emissions Standards

13. Emission Standards: Emissions from the CTG/HRSG system shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Initial and Annual Stack Tests 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr[f]	ppmvd @ 15% O_2
CO[a]	Oil	Combustion Turbine (CTG)	8.0	36.7	8.0, 24-hr
	Gas	CTG Normal	4.1	15.9	
		CTG & Duct Burner (DB)	7.6	37.2	
		CTG Low Load	NA	NA	
		CTG & PA with or w/o DB	NA	NA	14, 24-hr
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X[b]	Oil	CTG	8.0	60.3	8.0, 24-hr
	Gas	CTG Normal	2.0	12.7	2.0, 24-hr
		CTG & DB	2.0	16.1	
		CTG & PA with or w/o DB	NA	NA	
$PM/PM_{10}/PM_{2.5}$[c]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
Ammonia[e]	Oil/Gas	CTG, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the PA mode and all other modes based on the hours of operation for each mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content as detailed in Specific Condition 30. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed Specific Condition 30.

e. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 and EPA Method 320.

f. The mass emission rate standards are based on a turbine inlet condition of 70 °F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

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

Excess Emissions

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 13 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

14. Operating Procedures: BACT determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of the CTG, DB, HRSG, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

15. Definitions

a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(245), F.A.C.]

b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
[Rule 62-210.200(230), F.A.C.]

c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(159), F.A.C.]

16. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

17. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

18. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, and documented malfunctions shall be permitted, provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For the CTG/HRSG system, excess NO_X and CO emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

   a. *STG/HRSG System Cold Startup:* For cold startup of the STG/HRSG system, excess NO_X and CO emissions from the CTG/HRSG system shall not exceed six hours in any 24-hour period. A "cold startup of the STG/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

   {Permitting Note: During a cold startup of the steam turbine system, the CTG/HRSG system is brought on line at low load to gradually increase the temperature of the STG and prevent thermal metal fatigue}

   b. *STG/HRSG System Warm Startup:* For warm startup of the STG/HRSG system, excess NO_X and CO emissions shall not exceed four hours in any 24-hour period. A "warm startup of the STG/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

   c. *Shutdown:* For shutdown of the combined cycle operation, excess NO_X and CO emissions from the CTG/HRSG system shall not exceed three hours in any 24-hour period.

   d. *Fuel Switching:* Excess NO_X and CO emissions due to oil-to-gas fuel switching shall not exceed 1 hour in any 24-hour period.

19. Ammonia Injection: Ammonia injection shall begin as soon as operation of the CTG/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above condition allows excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the CTG/HRSG system including the pollution control equipment. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

20. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.
[Design; Rule 62-4.070(3), F.A.C.]

Emissions Performance Testing

21. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027 or 320	Procedure for Collection and Analysis of Ammonia in Stationary Source. {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.} Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.
[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

22. Initial Compliance Determinations: The CTG shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. The unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the CEMS shall also be reported. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate initial compliance with the CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. The Department may, for good reason, require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a) and (b), F.A.C. and 40 CFR 60.8]

23. Annual Compliance Tests: During each federal fiscal year (October 1st, to September 30th), CTG shall be tested to demonstrate compliance with the emission standard for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

24. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also

serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter. [Rule 62-212.400 (BACT), F.A.C.]

25. Compliance for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$: In stack compliance testing is not required for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$. Compliance with the limits and control requirements for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$ is based on the recordkeeping required in Specific Condition 30, visible emissions testing and CO continuous monitoring. [Rule 62-212.400 (BACT), F.A.C.

Continuous Monitoring Requirements

26. CEM Systems: The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitor:* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

    b. *NO_X Monitor:* The NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

    c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

27. CEMS Data Requirements:

    a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted.

b. *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, Subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *12-month Rolling Averages:* Compliance with the long-term emission limit for CO shall be based on a 12-month rolling average. Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months

e. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 18 and 20 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

f. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

28. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system prior to the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

Records and Reports

29. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the CTG and HRSG DB system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and fuel switching). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

30. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

31. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. *Natural Gas:* Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

    b. *ULSD Fuel Oil:* Compliance with the ULSD fuel oil sulfur limit shall be demonstrated by sampling and analysis of the fuel by the permittee or vendor for sulfur, and reporting the results to the Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or from an analysis conducted by the permittee, in accordance with the above methods. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

32. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

33. Excess Emissions Reporting:

a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Permit Limits Excess Emissions Report:* Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_X emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

c. *NSPS Semi-Annual Excess Emissions Reports:* Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority.

{Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, and 60.332(j)(1)]

34. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

B. Unit B Cooling Tower (EU 031)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
031	Unit B Cooling Tower – consisting of six cells with six individual exhaust fans

Equipment

1. Cooling Tower: The permittee is authorized to install one 6-cell wet evaporative mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 56,000 gallons per minute; drift eliminators; and a drift rate of no more than 0.0005 percent of the circulating water flow. [Application; Design]

Emissions and Performance Requirements

2. Drift Rate: Within 60 days of commencing commercial operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

   {Permitting Note: This work practice standard is established as BACT for PM/PM_{10}/$PM_{2.5}$ emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 3 tons of PM per year and less than 2 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}

SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS
C. Fuel Oil Storage Tank (EU 032)

ID	Emission Unit Description
032	One nominal 1 million gallons ultralow sulfur diesel (ULSD) fuel oil storage tank

NSPS Applicability

1. NSPS Subpart Kb Applicability: The distillate fuel oil tank is not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

Equipment Specifications

2. Equipment: The permittee is authorized to install, operate, and maintain one nominal 1 million gallon distillate fuel oil storage tank designed to provide ULSD fuel oil to Unit B or to other units on the site. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

Emissions and Performance Requirements

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

Notification, Reporting and Records

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the storage tank for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C]

5. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective MSDS for the ULSD fuel oil stored in the tanks. [62-4.070(3) F.A.C.]

SECTION IV. APPENDICES

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NSPS SUBPART A AND NESHAP SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

NSPS - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

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§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

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§ 60.14 Modification.

§ 60.15 Reconstruction.

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§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

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NSPS SUBPART A AND NESHAP SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

§ 63.8 Monitoring Requirements.

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§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

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Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Refer to the BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Fuel	Method of Operation	Initial and Annual Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @15% O_2	lb/hr[f]	ppmvd @ 15% O_2
CO[a]	Oil	Combustion Turbine (CTG)	8.0	36.7	8.0, 24-hr
	Gas	CTG Normal	4.1	15.9	
		CTG & Duct Burner (DB)	7.6	37.2	
		CTG Low Load	NA	NA	
		CTG & PA with or w/o DB	NA	NA	14, 24-hr
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X[b]	Oil	CTG	8.0	60.3	8.0, 24-hr
	Gas	CTG Normal	2.0	12.7	2.0, 24-hr
		CTG & DB	2.0	16.1	
		CTG & PA with or w/o DB	NA	NA	
$PM/PM_{10}/PM_{2.5}$[c]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
Ammonia[e]	Oil/Gas	CTG, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the PA mode and all other modes based on the hours of operation for each mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the permit.

e. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

f. The mass emission rate standards are based on a turbine inlet condition of 70 °F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

GENERAL CONDITIONS

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

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

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

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

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 (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
    d. Compliance with New Source Performance Standards (X).

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.

NSPS SUBPART KKKK REQUIREMENTS FOR GAS TURBINES

Stanton Unit B is regulated as Emissions Unit 030. The combustion turbine-electrical generator and the HRSG duct burner are part of the combined cycle unit. This emissions unit shall comply with all applicable requirements of this Subpart.

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

On July 6, 2006, EPA published the final NSPS Subpart KKKK (of 40 CFR 60) provisions for combustion turbines in the Federal Register. Subpart KKKK was adopted within Rule 62-204.800(8), F.A.C. Following is an abridged version of Subpart KKKK. The full provisions may be provided in full upon request and are also available beginning at Section 60.4300 at www.access.gpo.gov/nara/cfr/waisidx_07/40cfr60_07.html .

Source: Federal Register dated 7/6/06

Subpart KKKK--Standards of Performance for Stationary Combustion Turbines

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Table 1 to Subpart KKKK of Part 60. NO_X Emission Limits for New Stationary Combustion Turbines.*

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2or 54 ng/J of useful output (0.43 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2or 160 ng/J of useful output (1.3 lb/MWh).

* Only the NO_X Requirements applicable to the Stanton Unit B project.

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

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

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

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

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

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

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

12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

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

    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

14. Determination of Process Variables

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

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

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

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to

determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

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

RECORDS AND REPORTS

19. <u>Records Retention</u>: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

20. <u>Annual Operating Report</u>: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ______________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer: ____

Model No.: ____

Date of Latest CMS Certification or Audit: _______________________

Process Unit(s) Description: ____

Total source operating time in reporting period [1]: ______________________

Emission data summary [1]	CMS performance summary [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions .... ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. Total duration of excess emissions x (100) / [Total source operating time] .... ____ %[2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ %[2]

1 For opacity, record all times in minutes. For gases, record all times in hours.

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

Note: On a separate page, describe any changes since the last in CMS, process or controls.

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

Name: ____

Signature: ____ *Date*: ________________

Title: ____

SECTION IV. APPENDIX YYYY

NESHAP REQUIREMENTS FOR COMBUSTION TURBINES

The Stanton Unit B combustion turbine is to the applicable requirements of 40 CFR 63, Subpart YYYY. The provisions of this Subpart may be provided in full upon request.

Applicability of NESHAP Subpart YYYY

The West County Energy Center will be a major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines are subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit is considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine is subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @ 15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show continuous compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as those proposed for the West County Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY are:

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

Harvey, Mary

From: Harvey, Mary

Sent: Tuesday, March 25, 2008 3:39 PM

To: 'dstalls@ouc.com'; 'buddy.dyer@cityoforlando.net'; 'mayor@ocfl.net'; 'lori.cunniff@ocfl.net'; 'worley.gregg@epa.gov'; 'dee_morse@nps.gov'; Bradner, James; 'tdavis@ectinc.com'; Halpin, Mike; 'Forney.Kathleen@epamail.epa.gov'; 'little.james@epamail.epa.gov'

Cc: Linero, Alvaro; Walker, Elizabeth (AIR); Gibson, Victoria

Subject: ORLANDO UTILITIES COMMISSION - DEP FILE #0950137-020-AC (PSD-FL-373A)

Attachments: 0950137.020.AC.D_pdf.zip

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'mayor@ocfl.net'		
'lori.cunniff@ocfl.net'		
'worley.gregg@epa.gov'		
'dee_morse@nps.gov'		
Bradner, James	Delivered: 3/25/2008 3:39 PM	
'tdavis@ectinc.com'		
Halpin, Mike	Delivered: 3/25/2008 3:39 PM	Read: 3/25/2008 3:41 PM
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Harvey, Mary

From: Tom Davis [tdavis@ectinc.com]
Sent: Tuesday, March 25, 2008 4:06 PM
To: Harvey, Mary
Subject: RE: ORLANDO UTILITIES COMMISSION - DEP FILE #0950137-020-AC (PSD-FL-373A)

From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Tuesday, March 25, 2008 3:39 PM
To: dstalls@ouc.com; buddy.dyer@cityoforlando.net; mayor@ocfl.net; lori.cunniff@ocfl.net; worley.gregg@epa.gov; dee_morse@nps.gov; Bradner, James; tdavis@ectinc.com; Halpin, Mike; Forney.Kathleen@epamail.epa.gov; little.james@epamail.epa.gov
Cc: Linero, Alvaro; Walker, Elizabeth \(AIR\); Gibson, Victoria
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Harvey, Mary

From: Stalls, Denise M. [DStalls@ouc.com]
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To: Harvey, Mary
Subject: RE: ORLANDO UTILITIES COMMISSION - DEP FILE #0950137-020-AC (PSD-FL-373A)

received, thank you

From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Tue 3/25/2008 3:38 PM
To: Stalls, Denise M.; buddy.dyer@cityoforlando.net; mayor@ocfl.net; lori.cunniff@ocfl.net; worley.gregg@epa.gov; dee_morse@nps.gov; Bradner, James; tdavis@ectinc.com; Halpin, Mike; Forney.Kathleen@epamail.epa.gov; little.james@epamail.epa.gov
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