Memorandum

Florida Department of Environmental Protection

TO:	Michael G. Cooke, Director DARM
Through:	Trina L. Vielhauer, Chief BAR
Through:	A.A. Linero, P.E., Program Administrator, South Permitting Section
From:	Cindy Mulkey
DATE:	September 8, 2005
SUBJECT:	Keys Energy Services - 48 MW Simple Cycle Combustion Turbine DEP File No. 0870003-007-AC (PSD-FL-348)

Attached is the Final PSD Permit for Keys Energy Services Unit 4. The project is to construct a simple cycle combustion turbine and ancillary equipment at the existing Stock Island Power Plant near Key West. The unit is a 48 MW General Electric LM6000 PC with spray inter-cooling (SPRINT). A determination of Best Available Control Technology (BACT) was required for emissions of nitrogen oxides (NO_X) and particulate matter (PM/PM_{10}). Emissions of PM and PM_{10}, CO, sulfuric acid mist SO_2, and VOC will be minimized by the combustion of low sulfur fuel oil.

Unit 4 will be permitted at 2,500 hours per year while firing low sulfur fuel oil and using water injection for NO_X control to 42 ppm (24-hr block average). An increase in operation above 2,500 hours will require the installation of a selective catalytic reduction system for the control of NO_X to 5 ppm (24-hr block average). Because of a fuel use limitation, 9 ppm will be sufficient to keep emissions below the 40 tons per year PSD threshold.

We issued the draft permit in late May. Issuance of the final permit was delayed by Keys through request for extension of time to file a petition. They withdrew their latest request for enlargement of time allowing us to act on the final permit.

The combustion turbine has apparently been constructed at a GE facility and is undergoing testing. EPA OECA is still reviewing documents that FMPA believes support its claim that construction commenced (by the definition in 40 CFR 60, Subpart A) prior to the applicability date (February 18, 2005) of proposed Subpart KKKK – Standards of Performance for New Stationary Combustion Turbines.

We clarified in the attached Final Determination that EPA's decision on the date FMPA/KEYS commenced construction and Subpart KKKK applicability will be effective as soon as we receive the decision in writing. We believe FMPA/KEYS can accommodate the proposed rule requirements if applicable.

Issuance of the Final Permit now allows them to begin the necessary on-site construction of support facilities so that FMPA can meet its obligations to KEYS by their contract date of May 2006.

No comments were received from EPA or the public. Those received from KEYS were discussed and are addressed in the attached Final Determination to Issue a PSD Permit.

AAL/cem

Attachments

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street, PO Box 6100
Key West, Florida 33041-6100

DEP File No. PSD-FL-348
KEYS –Stock Island Unit 4
Monroe County

_______________________________________/

Enclosed is the Final Permit Number PSD-FL-348 (0870003-007-AC) to construct/install a nominal 48 MW simple cycle unit and auxiliary equipment at the Stock Island Power Plant near Key West, Monroe County. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were sent by U.S. Mail or electronic mail before the close of business on 9/12/05 to the person(s) listed:

Daniel Cassel, KEYS*
Edward Garcia, KEYS
Frederick Bryant, FMPA*
Susan Schumann, FMPA
Mayor, Key West
Chair, Monroe County BCC
Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Ron Blackburn, DEP SD
Stanley Armbruster, P.E., B&V

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.

[signature] 9/12/05
(Clerk) (Date)

FINAL DETERMINATION

Keys Energy Services

48 MW, Simple Cycle Fuel-oil Fired Combustion Turbine-Electrical Generator,

Fuel Oil Storage Tank and Water Storage Tank.

DEP File No. 0870003-007-AC (PSD-FL-348)

On June 2, 2005 the Florida Department of Environmental Protection (Department) distributed an "Intent to Issue Air Construction Permit" to construct a nominal 48 megawatt (MW) simple cycle combustion turbine at the existing Stock Island Power Plant near Key West in Monroe County.

The package included the Department's Draft Air Construction Permit, the "Intent to Issue Air Construction Permit," the "Technical Evaluation and Preliminary Determination," and the "Public Notice of Intent to Issue Air Construction Permit." The Department sent copies of the package to various persons, agencies, and municipalities. Keys Energy Services (KEYS) published the Public Notice in The Key West Citizen on June 5 and provided to the Department the required proof of publication.

On June 13 KEYS requested an extension of time to file a petition for an administrative hearing until August 15. On June 28 the Department granted this extension. On July 14 the Department transmitted a revised Draft Permit to serve as the basis for withdrawal of the request for extension of time to file a petition.

On August 15 KEYS requested a further extension of time to file a petition for an administrative hearing until September 30. On September 1 KEYS submitted a Notice of Withdrawal of Enlargement of Time" allowing the Department to issue this Final Determination.

The Department received no comments from agencies or the public regarding the Draft Air Construction Permit. By letter dated June 17 KEYS submitted comments which the Department received on June 20. By letter dated August 1, the Department received comments from EPA Region 4 limited to the Department's request that EPA review and approve the Department's preliminary determination that the project is not subject to 40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.

By letter dated August 18 KEYS transmitted further information to EPA and the Department to support its' position that Subpart KKKK does not apply to the project. The Department is awaiting EPA's decision on the matter but can proceed with this Final Determination while awaiting that decision. This will allow KEYS to begin on-site construction on the project.

The comments by KEYS include their proposed revisions listed below (*italics*) followed by the Department's response. All of the KEYS comments relate to the June 17 letter except as noted.

Any additions to permit conditions are underlined and deletions are indicated by strike-through notation.

1. *KEYS states: Based on a contract between GE and FMPA dated February 18, 2005, the combustion turbine specified in this permit is not subject to Proposed Subpart KKKK. (Reference Section I, Regulatory Classification)*

   The Department made a preliminary determination in agreement with KEYS' position and documented it in the draft permit. The Department requested approval by EPA at the time that the draft permit was distributed for public notice and comment. EPA is the agency with final authority on matters related to New Source Performance Standards (NSPS) applicability.

By letter dated August 1 from the Director of Air Pesticides, and Toxics Management Division, EPA Region 4 advised "without adequate documentation that the February 18, 2005, contract between FMPA will result in a continuous program of construction, the combustion turbine in question would be a 'new' facility subject to NSPS Subpart KKKK".

By letter dated August 18 FMPA submitted to the Department and EPA 4 additional documents and the timeline from 1997 through August 12, 2005 for the overall project to provide electrical power to KEYS including documents related to the purchase of the combustion turbine. In the transmittal letter KEYS states: "Clearly, FMPA/KEYS should not be subject to the NSPS regulations because it did not "commence construction after February 18 2005".

EPA reviewed the material provided. A teleconference was held on August 31 between the Florida Municipal Power Association (FMPA), KEYS, the Department, EPA Region 4, and EPA OECA to discuss the information submitted. EPA representatives asked a number of questions regarding the contract between FMPA and General Electric and the supporting materials. EPA advised that some time is required for internal consultation and review of their response. They will send their applicability determination to the Department who will advise FMPA/KEYS of EPA's decision.

At the time of this Final Permit Determination, the Department's preliminary determination regarding Subpart KKKK has not yet been approved by EPA. The Department will implement EPA's decision on the matter when it is issued in writing.

2. *KEYS requested clarification of the Department's determination and correction for the date of the proposed regulation in SECTION III, Part A, Condition 2(c) as follows: (Reference Section III, Part A, Condition 2(c).*

   See 1 and 2 above regarding the Department's preliminary determination. The Department agrees that the date of the proposed regulation given is in error. The Department will modify Section III, Part A, Condition 2(c) as follows:

   Subpart KKKK, Standards of Performance for Stationary Gas Turbines: The Department has made a preliminary determination subject to approval by EPA, that this regulation proposed on ~~January~~ February 18, 2005 does not apply to this project.

3. *KEYS requested clarification (and removal) of language regarding future installation of SCR system. (Reference Section III, Part A, Emission Controls, Specific Condition 12)*

   The Department agrees with the comment because other conditions (e.g. Specific Condition 7) already clarify exactly when an SCR system is required. As presently written the condition seems to suggest to KEYS that they will ultimately have to install an SCR system whether or not the unit ever operates more than 2500 hours during a 12-month period.

   Therefore the Department will clarify condition 12 as requested. Condition 7 (unchanged) is shown for comparison.

   CONDITION 7 (Unchanged)

   Hours of Operation: The combustion turbine shall operate no more than 2,500 hours based on a 12-month rolling total without installing a selective catalytic reduction (SCR) system. Exceeding this restriction shall require the installation and operation of an SCR system as required in III.B. [Applicant Request, Rules 62-210.200, (PTE) and 62-212.400(2)(g), F.A.C.]

   CONDITION 12

   Future Selective Catalytic Reduction (SCR): The permittee shall design and build the project to facilitate and not to hamper or preclude the future installation of the SCR system. ~~The combustion turbine may operate without the use of the SCR system for an initial period during which the total~~

~~hours of operation do not exceed 2,500 during any 12-month rolling total.~~
[Design and Rule 62-212.400, F.A.C.]

4. *KEYS requested removal of a permitting note in Section III, Part A, Condition 16. KEYS states "This permitting note is an editorial comment unrelated to this permit".*

   The permitting note seems to be an editorial note in the opinion of KEYS. However the Department considers it important to document the reason for the relatively high emission rates approved for this project within the same condition. This insures that reviewers and the public in other states will not misinterpret the conditions under which the emission limits were issued.

   The permitting note will not be removed. For reference the note states:

   {Permitting note: Pipeline natural gas is currently unavailable to the Keys. However, for a similar unit operating on natural gas and for a comparable number of hours, a BACT limit would likely be set at 15 ppmvd @ 15% O_2.}

5. *KEYS requested clarification of referenced specific condition in SECTION III, Part A, Condition 36 that it refers to Condition 42 instead of Condition 41.*

   The Department agrees with KEYS. The relevant portion of Condition 36 is modified as follows:

   CONDITION 36(c)

   Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (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. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition ~~41~~ 42 of this permit.

6. *KEYS requested clarification of language regarding future installation of SCR system, SECTION III. Part B, Combustion Turbine Water Injection and SCR & > 2,500 Hours. The requested clarification is that the 2,500 hours is on a 12-month rolling total.*

   The Department agrees. The requested modification in no way alters the intent or requirements of this permit and may serve as clarification for the applicant. The first paragraph in SECTION III, Part B is modified as follows:

   This section of the permit addresses the following new emissions unit upon exceeding 2,500 hours or operation on a 12-month rolling total and thereafter. Upon exceeding 2,500 hours of operation on a 12-month rolling total, the provisions of III.B supersede III.A for the rest of the operating life of the unit. BACT is water injection and SCR.

7. *KEYS requested clarification of the Department's determination and correction for the date of the proposed regulation (Subpart KKKK) in SECTION III, Part B, Condition 2(c).*

   Request and response are same as Item 2 above. Section III, Part B, Condition 2 (c) is revised as follows:

   Subpart KKKK, Standards of Performance for Stationary Gas Turbines: The Department has made a preliminary determination subject to approval by EPA, that this regulation proposed on ~~January~~ February 18, 2005 does not apply to this project.

8. *KEYS requested edit of SECTION III, Part B, Condition 6. to reflect the word "not" instead of "no".*

The Department agrees. Section III, Part B, Condition 6 is modified as follows:

Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. Total fuel usage shall ~~no~~ not exceed 13,600,000 gallons of fuel oil during any consecutive 12 months. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)].

9. *KEYS requested clarification (inclusion) of (reference) temperature of 41 °F in Section III, Part B, Condition 14 (note to table).*

The Department agrees. The change will not relax the emission limits. Section III, Part B, Condition 14 is modified as follows:

Note: Annual emissions, for the purposes of this table only, are based on ~~an ambient~~ a 41° F temperature~~s~~ and the equivalent of 4,420 hours of full load operation. PM/PM_{10} estimates are based on the equivalent of 8,760 hours of full load operation.

10. *KEYS requested editing (combination of) Section III, Part B, Specific Condition 25, (d) and (e).*

The Department agrees. The meaning of the condition is unchanged.

(c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines.

(d) EPA Method 25 or 25A – ~~(e)~~ Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions); and;

~~(f)~~ (e) Conditional Test Method 027 – Measurement of Ammonia Slip.

11. *KEYS requested clarification of referenced (SECTION III, Part B,) Specific Condition 37 that it refers to Specific Condition 43 instead of 42.*

The Department agrees with KEYS. The relevant portion of Condition 37 is modified as follows:

CONDITION 37(c)

Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (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. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition ~~42~~ 43 of this permit.

12. *By Notice dated September 1, 2005, KEYS withdrew its Request for Enlargement of Time that KEYS submitted on August 15, 2005. KEYS stated "Following discussions with Department representatives, KEYS and the Department have come to agreement on the issues involved in the above referenced Draft Permit, and KEYS understands that the Department will promptly issue a Final Permit".*

The Department agrees and will issue a Final Permit that is substantially the same as the revised draft previously transmitted to KEYS. The mentioned revision addressed all of KEYS comments with the exception of a final decision on Subpart KKKK applicability. No further comments were received by the Department in response to the revision transmitted to KEYS.

The final decision by the Department is to issue the permit with the changes noted. The Department will reopen the permit to include the final clarification of Subpart KKKK after EPA issues a written decision. The Department considers the pending applicability decision to be immediately effective when issued by EPA. Inclusion in the permit will be a ministerial function.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

PERMITTEE:

Keys Energy Services
1001 James Street
Key West, Florida 33401-6100

ARMS Permit No.	0870003-007-AC
PSD Permit No.	PSD-FL-348
SIC No.	4911
Expires:	July 31, 2007

Authorized Representative:
Daniel Cassel
Director of Generation

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality. The proposed project authorizes the installation of one nominal 48 megawatt, fuel oil-fired, simple cycle combustion turbine-electrical generator. This project additionally authorizes the installation of a nominal 1,000,000 gallon fuel oil storage tank and an additional water tank.

The project will be located at the Stock Island Power Plant near Key West, Monroe County. The physical address of the facility is 6900 Front Street, Stock Island. UTM coordinates for this facility are Zone 17; 425.65 km E; 2716.67 km N.

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 40 CFR 52.21. 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.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD	Best Available Control Technology (BACT) Determination
Appendix GC	General Conditions

Michael G. Cooke, Director
Division of Air Resource Management

Date:

FACILITY DESCRIPTION

The existing Stock Island Plant consists of two nominal 8.8 MW diesel generators, one nominal 23.5 MW simple cycle combustion turbine, two nominal 19.8 MW simple cycle combustion turbines and miscellaneous unregulated units. The proposed project is to install one nominal 48 MW simple cycle combustion turbine-electrical generator, one nominal 1,000,000 gallon fuel oil storage tank, and a water tank.

NEW EMISSIONS UNITS

The proposed project will result in the following new emissions units.

EU ID No.	Emissions Unit Description
011	General Electric LM 6000 PC SPRINT Combustion Turbine-Electrical Generator
012	One nominal 1,000,000 gallon Distillate Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

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

Title IV Acid Rain: This facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: This facility is a Title V major source of air pollution.

PSD Major Source: The project is located in an area designated as “attainment,” “maintenance,” or “unclassifiable” for each pollutant subject to a National Ambient Air Quality Standard. The facility is not one of the 28 PSD source categories, and is subject to the PSD applicability threshold of 250 tons per year. Potential emissions of at least one regulated pollutant exceed 250 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS Sources: The combustion turbine specified in this permit is also subject to regulation under the New Source Performance Standards for Stationary Gas Turbines, 40 CFR 60, Subpart GG and may be subject to Proposed Subpart KKKK.

NESHAP: The National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart YYYY for combustion turbines does not apply because the facility is not a major source of HAPS.

RELEVANT DOCUMENTS

- Air Construction/PSD Permit application received on October 14, 2004;
- First Department Request for Additional Information (RAI) dated November 10, 2004;
- Response to First RAI received on January 18, 2005;
- Supplement to First RAI Response received on February 18, 2005;
- Second Department RAI dated February 17, 2005;
- Response to Second RAI received on April 13, 2005;
- Technical Evaluation and Preliminary Determination May 31, 2005;
- Intent to Issue Air Construction/PSD Permit distributed May 31, 2005, and
- Final Determination Issued September 8, 2005.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.
2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the South District Office, Florida Department of Environmental Protection, 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-3381. The phone number is 239/332-6975 and the fax number is 239/332-6969.
3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code.
4. General Conditions: The owner and operator are subject to, and shall operate under the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated 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 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified.
7. Permit Expiration: 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, and 62-210.300(1), F.A.C]
8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C.]
9. 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.]
10. Modifications: No emissions unit or facility subject to this permit 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.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. 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 Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. COMBUSTION TURBINE (EU 011) WATER INJECTION ONLY & ≤ 2,500 HOURS

This section of the permit addresses the following new emissions unit for the period during which the unit operates for 2,500 hours or less on a rolling 12-month total and with water injection only. Upon reaching the first rolling 12-month total of 2,501, section III.B. of this permit will supersede all conditions in this section(III.A.).

E.U. ID No.	Common Emission Unit Description
011	General Electric LM 6000 PC Sprint Combustion Turbine-Electrical Generator

Applicable Standards and Regulations

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for nitrogen oxides (NO_X), and particulate matter (PM_{10}). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (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 GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (c) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** The Department has made a preliminary determination subject to approval by EPA, that this regulation proposed on February 18, 2005 does not apply to this project.

Performance Restrictions

3. Combustion Turbine: The permittee is authorized to install, tune, operate and maintain one simple cycle combustion turbine-electrical generator with spray intercooling and water injection (General Electric Model LM6000 PC SPRINT). The unit is designed to produce approximately 48 MW of electrical power at ISO conditions. [Applicant Request]

4. Permitted Capacity: The heat input to the combustion turbine from firing No. 2 fuel oil shall not exceed 434 MMBtu per hour (LHV) based on the following: 100% base load, lower heating value of No. 2 fuel oil, and a compressor inlet air temperature of 41° F. 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. Heat input rates will vary depending upon compressor conditions and the combustion turbine characteristics. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves on file with the Department.
   [Design, Rule 62-210.200, F.A.C. (Definition - PTE)]

5. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle conversion which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built.
[Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.] (See III.B. for BACT if increased hours of operation.)

6. Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit.
[Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)`]

{Permitting note: Pipeline natural gas is currently unavailable to the Keys.}

7. Hours of Operation: The combustion turbine shall operate no more than 2,500 hours based on a 12-month rolling total without installing a selective catalytic reduction (SCR) system. Exceeding this restriction shall require the installation and operation of an SCR system as required in III.B.
[Applicant Request, Rules 62-210.200, (PTE) and 62-212.400(2)(g), F.A.C.]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

9. 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 the 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.]

EMISSIONS CONTROLS

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

11. Water Injection Technology: The permittee shall install, calibrate, tune, operate, and maintain a water injection system designed to achieve the permitted NO_x emissions standards for the unit.
[Applicant request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

12. Future Selective Catalytic Reduction (SCR): The permittee shall design and build the project to facilitate and not to hamper or preclude the future installation of the SCR system.
[Design and Rule 62-212.400, F.A.C.]

13. 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.]

EMISSIONS STANDARDS

14. Summary: The following table summarizes the emissions standards for each pollutant and total emissions in lb/hr and TPY for informational and convenience purposes (PTE) only, and shall not be considered permit limits. This table does not supersede any of the terms or conditions of this permit.

Pollutant	Emission Standard/Limit	Emissions (lb/hr)	Emissions (TPY)
NO_X	42 ppmvd @ 15% O_2	75.9	94.9
CO	30 ppmvd @ 15% O_2	33.0	41.0
SO_2	0.05 percent sulfur fuel oil	23.6	29.5
SAM	0.05 percent sulfur fuel oil	5.4	6.8
PM/PM_{10}	VE = 10% as surrogate	25.0 (front and back)	31.3
PM/PM_{10}	VE = 10% as surrogate	13.9 (front half)	17.4
VOC	16 ppmvd @ 15% O_2	10.0	12.6

Note: Annual emissions, for the purposes of this table only, are based on a 41° F temperature and 2,500 hours of full load operation.

15. Carbon Monoxide (CO):

CO emissions from the combustion turbine shall not exceed 30.0 ppmvd @15% O_2. CO emissions shall not exceed 33.0 pounds per hour. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with EPA Method 10 and the requirements of this permit.
[Rule 62-212.400, F.A.C. (PSD Avoidance)]

16. Nitrogen Oxides (NO_X):

This emissions limit applies during the initial phase of operation when the combustion turbine operates no more than 2,500 hours based on a 12-month rolling total:

NO_X emissions from the combustion turbine shall not exceed a BACT emission limit of 42 ppmvd @15% O_2 during initial and annual tests nor exceed 42.0 ppmvd @15% O_2 on a 24-hour block average while firing fuel oil. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with 40 CFR Part 60 Subpart GG and based on a 24-hour block average for data collected from the continuous emissions monitor.
[Rule 62-212.400, F.A.C. (BACT)]

{Permitting note: Pipeline natural gas is currently unavailable to the Keys. However, for a similar unit operating on natural gas and for a comparable number of hours, a BACT limit would likely be set at 15 ppmvd @ 15% O_2.}

17. Particulate Matter (PM/PM_{10}) and Visible Emissions (VE)

Emissions of PM and PM_{10} shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. Visible emissions from the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM10 emission limits.
[Rules 62-4.070(3) and 62-212.400, F.A.C. (PSD Applicability)]

18. Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

Emissions of SAM and SO_2 shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. SAM and SO_2 emissions shall not exceed 6.8 and 29.5 tons per year, respectively. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the fuel records specified by this permit.
[Rules 62-4.070(3), and 62-212.400, F.A.C. (BACT)].

19. Volatile Organic Compounds (VOC):

VOC emissions from the combustion turbine shall not exceed 16.0 ppmvd corrected to 15% oxygen for each fuel. VOC emissions shall not exceed 10.0 pounds per hour. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting initial tests in accordance with EPA Methods 25 and/or 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions.
[Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Section III.A. of this permit. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

20. Definitions

(a) *Excess Emissions* are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction.
[Rule 62-210.200(106), F.A.C.]

(b) *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(246), F.A.C.]

(c) *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
[Rule 62-210.200(231), F.A.C.]

(d) *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(160), F.A.C.]

21. Startup, Shutdown, Malfunction: 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 case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A written report summarizing each malfunction resulting in excess emissions shall be submitted in a quarterly report.
[Rule 62-210.700(1) and (6), F.A.C.]
   (a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for more than 2 hours in any 24-hour block averaging period.
   [Design; Rule 62-210.700(1) and (5), F.A.C.]
   (b) During all startups, shutdowns, and malfunctions, the NO_x continuous emissions monitoring System (CEMS) shall monitor and record emissions. Up to 2 hours (120 minutes) of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. However, only data obtained during startups, shutdowns, and documented malfunctions may be used for the 2 hour exclusion period. Other arbitrary high readings may not be excluded from compliance averaging periods.
   [Rule 62-210.700(1) and (5), F.A.C.]
   (c) A documented malfunction means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile, or electronic mail. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
   [Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]
22. Prohibition: 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.
[Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

23. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
[Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]
24. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.
   (a) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources;
   (b) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources;

(c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines; and

(d) EPA Method 25 or 25A - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions).

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure specified in Rule 62-297.620, F.A.C.

25. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial NSPS performance tests and at least 15 days prior to any other required tests. [40 CFR 60.7, 40 CFR 60.8 and Rule 62-297.310(7)(a)9., F.A.C.]

26. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NO_X, VOC, and visible emissions. Initial NO_X performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and shall also be converted into units of the NSPS emissions standard.
[Rule 62-297.310(7)(a)1., F.A.C.]

27. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X, CO, and visible emissions from the combustion turbine for each fuel. If conducted at permitted capacity, NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). In the event that the operation of the CT is less than 400 hours per year, annual testing is not required for that year.
[Rule 62-297.310(7)(a), F.A.C.]

28. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NO_X, and visible emissions from the combustion turbine. VOC emission tests are not required prior to permit renewal provided the CO emission standards are met. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision.
[Rule 62-297.310(7)(a)3., F.A.C.]

29. Tests After Major Repairs or Replacements: The Department may require that additional compliance testing be conducted within 90 days after major repairs or replacements are performed.
[Rule 62-297.310(7)(a)4., F.A.C.]

30. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However,

subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C.
[Rule 62-297.310(2), F.A.C.]

31. 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.]

32. Applicable Test Procedures
   (a) Required Sampling Time.
      1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
      [Rule 62-297.310(4)(a)1., F.A.C.]
      2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
      [Rule 62-297.310(4)(a)2., F.A.C.]
   (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.
   [Rule 62-297.310(4)(b), F.A.C.]
   (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)(d), F.A.C.]

33. 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.
   [Rule 62-297.310(5)(a), F.A.C.]
   (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)(b), F.A.C.]

34. 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.]

CONTINUOUS MONITORING REQUIREMENTS

35. NO_X CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NO_X and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NO_X monitoring devices shall comply with the requirements of 40 CFR 60.334(b) for 40 CFR Part 75 monitoring systems. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location.
[Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

36. NO_X CEMS Data Requirements:

(a) Installation. The CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and 40 CFR 60.334(b).

(b) 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. A valid hour is one in which at least 1 data point is recorded in each quadrant during which the unit was operating.

(c) Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (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. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition 42 of this permit.

(d) Data Exclusion. As provided in III.A. 21-22., valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit. Up to 2 hours of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-297.520, F.A.C and 40 CFR 60.7].

37. Hours of Operation: Using a component of the gas turbine control system, the permittee shall monitor and record the hours of gas turbine operation. Within five working days following the end of each calendar month, the permittee shall record the total hours of operation (including hours during startups, shutdowns, and malfunctions) for the current month, and the total hours of operation for the current month plus the preceding 11 months.
[Rule 62-204.070, F.A.C., and Applicant Request]

COMPLIANCE DEMONSTRATIONS

38. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 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.]

39. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits for fuel oil specified in this permit by maintaining records required by 40 CFR 60.334 and 60.335.
[Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

40. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of operation and amount of fuel fired for the combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. All hours of operation (including hours during startups, shutdowns, and malfunctions) shall be included in the demonstration of compliance with the 12-month fuel usage limitations. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority.
[Rule 62-4.160(15), F.A.C.]

REPORTS

41. 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.
[Rule 62-297.310(8), F.A.C.].

42. Excess Emissions Reporting:

(a) If excess NO_X or visible emissions 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) NSPS Semi-Annual Reports. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report

A. COMBUSTION TURBINE (EU 011) WATER INJECTION ONLY & ≤ 2,500 HOURS

on any periods of excess emissions that occurred during the previous semi-annual to the Compliance Authority.

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

(c) SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NOx emissions in excess of the BACT permit standards at Specific Condition 16 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.

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

43. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours 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.]

44. Hours of Operation: Within ten working days following the first consecutive 12-month period in which the hours of operation exceed 2,500, the permittee shall notify the Compliance Authority. The notification shall include a summary of operation for the last 12 months, and the expected date of initial operation of the SCR system for the control of NO_X as required by III.B.
[Rule 62-204.070, F.A.C., and Applicant Request]

B. COMBUSTION TURBINE (EU 011) WATER INJECTION AND SCR & > 2,500 HOURS

This section of the permit addresses the following new emissions unit upon exceeding 2,500 hours of operation on a 12-month rolling total and thereafter. Upon exceeding 2,500 hours of operation on a 12-month rolling total, the provisions of III.B. supersede III.A. for the rest of the operating life of the unit. BACT is water injection and SCR.

E.U. ID No.	Common Emission Unit Description
011	General Electric LM 6000 PC Sprint Combustion Turbine-Electrical Generator

Applicable Standards and Regulations

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for nitrogen oxides (NO_X), and particulate matter (PM_{10}). Practicably enforceable limits have been established for sulfur dioxide (SO_2), and sulfuric acid mist (SAM) to avoid BACT determinations for these pollutants.
[Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (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 GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (c) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** The Department has made a preliminary determination, subject to approval by EPA, that this regulation proposed on February 18, 2005 does not apply to this project.

Performance Restrictions

3. Combustion Turbine: The permittee is authorized to install, tune, operate and maintain one simple cycle combustion turbine-electrical generator with spray intercooling and water injection (General Electric Model LM6000 PC SPRINT). The unit is designed to produce approximately 48 MW of electrical power at ISO conditions. [Applicant Request]

4. Permitted Capacity: The heat input to the combustion turbine from firing No. 2 fuel oil shall not exceed 434 MMBtu per hour (LHV) based on the following: 100% base load, lower heating value of No. 2 fuel oil, and a compressor inlet air temperature of 41° F. If different from the information provided in accordance with Specific Condition III.A.4, 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. Heat input rates will vary depending upon compressor conditions and the combustion turbine characteristics. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves on file

with the Department.
[Design, Rule 62-210.200, F.A.C. (Definition - PTE)]

5. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle operation which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built.
[Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.]

6. Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. Total fuel usage shall not exceed 13,600,000 gallons of fuel oil during any consecutive 12 months.
[Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)].

7. Hours of Operation: The combustion turbine may operate 8,760 hours per year.
[Applicant Request, Rule 62-210.200, F.A.C. (PTE)]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

9. 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 the 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.]

EMISSIONS CONTROLS

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

11. Water Injection Technology: The permittee shall install, calibrate, tune, operate, and maintain a water injection system designed to achieve the permitted NO_x emissions standards for the unit in conjunction with the SCR system.
[Applicant request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

12. Selective Catalytic Reduction (SCR): Within two months after exceeding the 12-month rolling total of 2,500 operating hours, the permittee shall install, calibrate, tune operate and maintain an SCR system designed to achieve the permitted NOx emissions standards for the unit in conjunction with the water injection system.
[Design and Rule 62-212.400, F.A.C.]

13. 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.]

EMISSIONS STANDARDS

14. Summary: The following table summarizes the emissions standards for each pollutant and total emissions in lb/hr and TPY for informational and convenience purposes (PTE) only and shall not be considered permit limits. This table does not supersede any of the terms or conditions of this permit.

Pollutant	Emission Standard/Limit	Emissions (lb/hr)	Emissions (TPY)
NO_X	9 ppmvd @ 15% O_2 24-hr block average	16.3	36.0
CO	20.0 ppmvd @ 15% O_2	20.0	44.2
SO_2	0.05 percent sulfur fuel oil	23.6	39.9
SAM	0.05 percent sulfur fuel oil	5.4	6.9
PM/PM_{10}	VE = 10% as surrogate 0.05 percent sulfur fuel oil	25.0	109.5
PM	VE = 10% as surrogate 0.05 percent sulfur fuel oil	25.0	109.5
VOC	8.0 ppmvd @ 15% O_2	5.0	11.0

Note: Annual emissions, for the purposes of this table only, are based on a 41° F temperature and the equivalent of 4,420 hours of full load operation. PM/PM_{10} estimates are based on the equivalent of 8,760 hours of full load operation.

15. Carbon Monoxide (CO):

CO emissions from the combustion turbine shall not exceed 20.0 ppmvd @15% O_2. CO emissions shall not exceed 20.0 lbs per hour. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with EPA Method 10 and the requirements of this permit.
[Rule 62-212.400, F.A.C. (PSD Avoidance)]

16. Nitrogen Oxides (NO_X):

The combustion turbine and SCR system shall be designed and constructed to meet an emission limit of 5.0 ppmvd @15% O_2. This shall be demonstrated during each initial test following installation of new catalyst. During normal operation, NO_x emissions shall not exceed 9.0 ppmvd @15% O_2 on a 24-hour block average. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with 40 CFR Part 60 Subpart GG and based on a 24-hour block average for data collected from the

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

{Permitting note: The 5.0 ppmvd value reflects BACT. The 9.0 ppmvd value is based on the fuel use limitation that would limit NO_x emissions to less than 40 tons per year. The Department will revise the higher long term limit downward in conjunction with any future applications that will increase fuel use above 13,600,000 gallons per year.}

17. Ammonia (NH_3)

The ammonia slip rate shall be limited to 10.0 ppmvd @ 15% O_2.
[Rule 62-212.400, F.A.C. (BACT).

18. Particulate Matter (PM/PM_{10})

Emissions of PM and PM_{10} shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. Visible emissions from the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM_{10} emission limits.
[Rule 62-212.400, F.A.C. (PSD Applicability)]

19. Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

Emissions of SAM, and SO_2 shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. SAM and SO_2 emissions shall not exceed 6.9 and 39.9 tons per year, respectively. Compliance with the SO_2 limit provides assurance that SAM emissions stay within permitted limits. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the records specified by this permit.
[Rule 62-212.400, F.A.C. (BACT)].

20. Volatile Organic Compounds (VOC):

VOC emissions from the combustion turbine shall not exceed 8.0 ppmvd corrected to 15% oxygen for each fuel. VOC emissions shall not exceed 5.0 pounds per hour. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting initial tests in accordance with EPA Methods 25 and/or 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions.
[Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Section III.B. of this permit. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

21. Definitions

(a) *Excess Emissions* are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction.
[Rule 62-210.200(106), F.A.C.]

(b) *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(246), F.A.C.]

(c) *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
[Rule 62-210.200(231), F.A.C.]

(d) *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(160), F.A.C.]

22. Startup, Shutdown, Malfunction: 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 case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A written report summarizing each malfunction resulting in excess emissions shall be submitted in a quarterly report.
[Rule 62-210.700(1) and (6), F.A.C.]

(a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for more than 2 hours in any 24-hour block averaging period.
[Design; Rule 62-210.700(1) and (5), F.A.C.]

(b) During all startups, shutdowns, and malfunctions, the NO_x continuous emissions monitoring System (CEMS) shall monitor and record emissions. Up to 2 hours (120 minutes) of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. However, only data obtained during startups, shutdowns, and documented malfunctions may be used for the 2 hour exclusion period. Other arbitrary high readings may not be excluded from compliance averaging periods.
[Rule 62-210.700(1) and (5), F.A.C.]

(c) A documented malfunction means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile, or electronic mail. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

23. Prohibition: 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.
[Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

24. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in

accordance with Rule 62-297.310(6), F.A.C. KEYS shall advise the Department of any requirements within the cited rule that would be incompatible with the operation of an SCR system or unadvisable due to storm design criteria.
[Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

25. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

(a) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources;

(b) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources;

(c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines.

(d) EPA Method 25 or 25A - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions); and

(e) Conditional Test Method 027 – Measurement of Ammonia Slip.

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure specified in Rule 62-297.620, F.A.C.

26. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial NSPS performance tests and at least 15 days prior to any other required tests.
[40 CFR 60.7, 40 CFR 60.8 and Rule 62-297.310(7)(a)9., F.A.C.]

27. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NO_X, VOC, ammonia slip and visible emissions. Initial NO_X performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and shall also be converted into units of the NSPS emissions standard.
[Rule 62-297.310(7)(a)1., F.A.C.]

28. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X, CO, and visible emissions from the combustion turbine for each fuel. Testing for ammonia slip is required during the first scheduled annual performance tests after the cumulative hours of operation exceed 1,500 actual hours starting from the initial installation of the SCR catalyst. Thereafter, ammonia testing is required during the first scheduled annual performance tests after subsequent cumulative 1,500 hours of operation or after regeneration, replacement or addition to the SCR catalyst system. If conducted at permitted capacity, NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). In the event that the operation of the CT is less than 400 hours per year, annual testing is not required for that year.
[Rule 62-297.310(7)(a), F.A.C.]

29. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NO_X, and visible emissions from the combustion turbine. VOC

emission tests are not required prior to permit renewal provided the CO emission standards are met. Testing for ammonia slip meeting the requirements of Condition 26, Annual Performance Tests will meet the requirements of this condition. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision.
[Rule 62-297.310(7)(a)3., F.A.C.]

30. Tests After Major Repairs or Replacements: The Department may require that additional compliance testing be conducted within 90 days after major repairs or replacements are performed.
[Rule 62-297.310(7)(a)4., F.A.C.]

31. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C.
[Rule 62-297.310(2), F.A.C.]

32. 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.]

33. Applicable Test Procedures

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
[Rule 62-297.310(4)(a)1., F.A.C.]

2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
[Rule 62-297.310(4)(a)2., F.A.C.]

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

(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)(d), F.A.C.]

34. 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.
[Rule 62-297.310(5)(a), F.A.C.]

(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)(b), F.A.C.]

35. 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.]

CONTINUOUS MONITORING REQUIREMENTS

36. NO_X CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NO_X and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NO_X monitoring devices shall comply with the requirements of 40 CFR 60.334(b) for 40 CFR Part 75 monitoring systems. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location.
[Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

37. NO_X CEMS Data Requirements:

(a) Installation. The CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and 40 CFR 60.334(b).

(b) 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. A valid hour is one in which at least 1 data point is recorded in each quadrant during which the unit was operating.

(c) Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (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. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition 43 of this permit.

(d) Data Exclusion. As provided in III.B. 21-22, valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit. Up to 2 hours of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-297.520, F.A.C and 40 CFR 60.7].

38. Hours of Operation: Using a component of the gas turbine control system, the permittee shall monitor and record the hours of gas turbine operation. Within five working days following the end of each calendar month, the permittee shall record the total hours of operation (including startups, shutdowns, and malfunctions) for the current month, and the total hours of operation for the current month plus the preceding 11 months.
[Rule 62-204.070, F.A.C., and Applicant Request]

COMPLIANCE DEMONSTRATIONS

39. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 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.]

40. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits for fuel oil specified in this permit by maintaining records required by 40 CFR 60.334 and 60.335 and the provisions of 40 CFR 75 Appendix D.
[Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

41. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of operation and amount of each fuel fired for the combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. All hours of operation shall be included in the demonstration of compliance with the 12-month fuel usage limitations. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority.
[Rule 62-4.160(15), F.A.C.]

REPORTS

42. 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.
[Rule 62-297.310(8), F.A.C.].

43. Excess Emissions Reporting:

(a) If excess NO_X or visible emissions 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) NSPS Semi-Annual Reports. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. 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 to the Compliance Authority.

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

(c) SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NOx emissions in excess of the BACT permit standards at Specific Condition 16 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.

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

44. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual fuel usage 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.]

DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
012	One distillate fuel oil storage tank for Combustion Turbine Unit 4 (approximately 1.0 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: As revised October 15, 2003, NSPS Subpart K does not apply to storage vessels which store a liquid with a vapor pressure less than 3.5 kPa.

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 1.0 million gallon distillate fuel oil storage tank designed to provide low sulfur fuel oil to Combustion Turbine Unit 4 or any other units on the site.
   [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

   {Note: Emissions of VOC from this unit are estimated to be less than one ton per year.}

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.]

Refer to the draft BACT proposal discussed in the Technical Evaluation for this project for the rationale regarding the following BACT determination.

For operation 2,500 hours or less, the following BACT determination applies:

a. <u>NO_x</u>, - 42.0 ppm @ 15% O_2 (75.9 lb/hr) while firing oil.

   Continuous compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS and based on a 24-hr block average. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG and certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

b. PM/PM_{10} - distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight, and visible emissions ≤ 10% opacity, based on a 6-minute average.

   The sulfur fuel specifications combined with the efficient combustion design and operation of the gas turbine represent (BACT) for PM/PM_{10} emissions. Compliance with the fuel specification and visible emissions standards shall serve as indicators of good combustion. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM10 emission limits. Compliance with the fuel specification shall be demonstrated by keeping records of the fuel sulfur content.

c. The mass emission rate standards are based on a turbine inlet condition of 41° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

For operation greater than 2,500 hours, the following BACT determination applies:

a. NOx - 5 ppm @ 15% O_2 (8.9 lb/hr) while firing oil.

   Compliance with the NO_x standards shall be demonstrated by conducting tests in accordance with EPA Method 7E or Method 20. Tests associated with demonstration of compliance with 40 CFR 60, Subpart GG and certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

d. PM/PM_{10} - distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight, and visible emissions ≤ 10% opacity, based on a 6-minute average.

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

b. The mass emission rate standards are based on a turbine inlet condition of 41° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Program Administrator A A Linero 9/8/2005
South Permitting Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

Trina L Vielhauer
Trina L. Vielhauer, Chief
Bureau of Air Regulation

Sept. 8, 2005
Date

Approved By:

Michael G. Cooke
Michael G. Cooke, Director
Division of Air Resources Management

9-9-05
Date

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

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Frederick Bryant
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

B. Received by (Printed Name)

C. Date of Delivery 9/14/05

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number
(Transfer from service label) 7004 1350 0000 1910 4182

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

7004 1350 0000 1910 4182

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Return Reciept Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

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Mr. Frederick Bryant
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819

PS Form 3800, June 2002 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33041-6100

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X K. Mesa
☐ Agent
☐ Addressee

B. Received by (Printed Name) K MESA

C. Date of Delivery 9-16-05

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

2005

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7004 1350 0000 1910 4175

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

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7004 1350 0000 1910 4175

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Restricted Delivery Fee (Endorsement Required)	

Postmark Here

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33041-6100

PS Form 3800, June 2002 See Reverse for Instructions

Florida Municipal Power Agency

Tina Garza
Document Control Technician

Via Federal Express

June 20, 2005

RECEIVED
JUN 21 2005
BUREAU OF AIR REGULATION

Ms. Cindy Mulkey
DEP
Division of Air Resource Management
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399

Dear Ms. Mulkey:

Enclosed you will find the original newspaper verification notice along with a copy of the published Notice of Intent to Issue Air Construction Permit for the Key West CT #4, this information was also faxed to you on June 14, 2005.

If you need anything further please call me at 321-239-1020.

Sincerely,

Tina Garza

Tina Garza
Document Control Technician

Enclosures

8553 Commodity Circle | Orlando, FL 32819-9002
T. (407) 355-7767 | Toll Free (888) 774-7606
F. (407) 355-5794 | www.fmpa.com
tina.garza@fmpa.com

THE CITIZEN KEY WEST
The Florida Keys Only Daily Newspaper, Est. 1876
Cooke Communications, LLC
Florida Keys

Mary Beth Canitano
Advertising Coordinator

PO Box 1800
Key West Fl 33041
Office..........305-292-7777
Extension.................x219
Fax.............305-294-0768
mcanitano@keysnews.com

STATE OF FLORIDA
COUNTY OF MONROE

Before the undersigned authority personally appeared Randy G. Erickson, who on oath says that he is Vice-President of Advertising Operations of the Key West Citizen, a daily newspaper published in Key West, in Monroe County, Florida; that the attached copy of advertisement, being a legal notice in the matter of Stock Island

In the ______________ Court, was published in said newspaper in the issues of June 5, 2005.

Affiant further says that the Key West Citizen is a newspaper published in Key West, in said Monroe County, Florida and that the said newspaper has heretofore been continuously published in said Monroe County, Florida every and has been entered as second-class mail matter at the post office in Key West, in said Monroe County, Florida, for a period of 1 year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

RG Erickson

Signature of Affiant

Sworn and subscribed before me this 14 day of June, 2005

Mary Beth Canitano

Mary Beth Canitano, Notary Public

Expires: January 15, 2007

Notary Seal

MARY BETH CANITANO
Notary Public - State of Florida
My Commission Expires Jan 15, 2007
Commission # DD178046
Bonded By National Notary Assn.
NOTARY PUBLIC STATE OF FLORIDA

Personally Known x Produced Identification _______

Type of Identification Produced ____________________

BEST AVAILABLE COPY

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 0870003-0070-AC (PSD-FL-348)
KEYS Stock Island Power Plant Combustion Turbine Unit 4
Monroe County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Keys Energy Services to construct a nominal 48 megawatt (MW) simple cycle combustion turbine at the existing Stock Island Power Plant near Key West, Monroe County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of nitrogen oxides (NO_X) and particulate matter (PM/PM_{10}). The applicant's address is Keys Energy Services (KEYS), 1001 James Street, Key West, Florida 33041-6100.

The applicant proposes to construct a new combustion turbine-electrical generator (Combustion Turbine Unit 4). The primary components are: one nominal 48 MW General Electric LM6000 PC combustion turbine-electrical generator with spray intercooling (SPRINT); a 60-foot exhaust stack; a nominal 1,000,000 gallon fuel oil storage tank; a new water tank; and other associated support equipment.

Combustion Turbine Unit 4 will be permitted to operate 2,500 hours per year while firing low sulfur fuel oil (0.05 percent sulfur). Water injection into the combustion area will be practiced for NO_X control.

The Department has determined that BACT for NO_X is 42.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmvd@15%O_X) under the very special circumstances of this project including location, lack of natural gas supply, low annual emissions for the project, installation of a single unit, etc. This limit will be achieved by water injection. Future increases in hours of operation will require installation of a selective catalytic reduction (SCR).

Emissions of carbon monoxide (CO), PM/PM_{10}, sulfuric acid mist (SAM), sulfur dioxide (SO_2), and VOC will be minimized by the efficient, high-temperature combustion of low sulfur fuel oil. A BACT determination was not required for CO, SAM, SO_2, or VOC.

KEYS' estimates of maximum potential annual emissions from Combustion Turbine Unit 4 are summarized in the following table. Actual emissions will be substantially less than estimated because much of the operation will be under low load conditions. For example, KEYS estimates that if it actually operates the unit for 2,500 hours per year, emissions will actually be less than 60 tons per year of NOx considering low load versus the estimate of 95 given below.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	34	100	No
Pb	0.013	0.6	No
NO_X	95	40	Yes
PM/PM_{10}	31/31	25/15	Yes
SO2	30	40	No
SAM	<7	7	No
VOC	7	40	No

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 (i.e. PSD Class II Areas) Therefore; multi-source modeling was not required for ambient air quality standards Class II increments.

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purpose during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection	Dept. of Environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Southeast District Office	South District Branch Office
111 S. Magnolia Drive, Suite 4	400 North Congress Avenue	2796 Overseas Highway,
Tallahassee, Florida 32399-2400	West Palm Beach, Fl 33415-5425	Suite 221
Telephone: 850/488-0114	Telephone: 561/681-6600	Marathon, Florida 33050
Fax: 850/922-6979	Fax: 561/681-6790	Telephone: 305/289-2310

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the Authorized representative, exclusive of confidential records under Section 403.111,F.S. Interested persons may contact the Program Administrator, South Permitting Section, Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/Air/permitting/construction/stockisland.htm

June 5, 2005

170516

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

May 31, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33041-6100

Re: Keys Energy Services Stock Island Power Plant
Combustion Turbine Unit 4 – GE LM6000 SPRINT
File No. 0870003-007-AC (PSD-FL-348)

Dear Mr. Cassel:

Enclosed are documents indicating the Department's intent to issue an air construction permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to Keys Energy Services for construction of a 48 megawatt simple cycle unit at the Stock Island Power Plant. The documents include: the "Intent to Issue Air Construction Permit;" the "Public Notice of Intent to Issue Air Construction Permit;" the Department's "Technical Evaluation and Preliminary Determination" including a draft determination of Best Available Control Technology; and the Draft Permit.

The Public Notice must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven (7) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Mr. A. A. Linero, Program Administrator, South Permitting at the above letterhead address. If you have any questions, please call Debbie Nelson at 850/921-9537 or Mr. Linero at 850/921-9523.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer, Chief,
Bureau of Air Regulation

TLV/aal

Enclosures

In the Matter of an
Application for Permit by:

Keys Energy Services (KEYS)
1001 James Street
Key West, Florida 33041-6100

Authorized Representative:
Mr. Daniel Cassel, Director of Generation

DEP File No. 0870003-007-AC
Draft Permit No. PSD-FL-348
KEYS Stock Island Power Plant
48 MW Combustion Turbine Unit 4

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD), copy of DRAFT Permit attached, for the proposed project as detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination for the reasons stated below.

The applicant, Keys Energy Services, applied on October 14, 2004 (application revised on April 13, 2005) to the Department for an air construction permit for a nominal 48 megawatt simple combustion turbine project at the Stock Island Power Plant near Key West, Monroe County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit is required.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting 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 Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

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

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

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

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

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 Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6/2/05 to the persons listed:

Daniel Cassel, KEYS*
Edward Garcia, KEYS
Frederick Bryant, FMPA*
Susan Schumann, FMPA
Mayor, Key West
Chair, Monroe County BCC
Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Ron Blackburn, DEP SD
Stanley Armbruster, P.E., B&V

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. Harvey 6/2/05
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0870003-007-AC (PSD-FL-348)

KEYS Stock Island Power Plant Combustion Turbine Unit 4
Monroe County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Keys Energy Services to construct a nominal 48 megawatt (MW) simple cycle combustion turbine at the existing Stock Island Power Plant near Key West, Monroe County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of nitrogen oxides (NO_X) and particulate matter (PM/PM_{10}). The applicant's address is Keys Energy Services (KEYS), 1001 James Street, Key West, Florida 33041-6100.

The applicant proposes to construct a new combustion turbine-electrical generator (Combustion Turbine Unit 4). The primary components are: one nominal 48 MW General Electric LM6000 PC combustion turbine-electrical generator with spray intercooling (SPRINT); a 60-foot exhaust stack; a nominal 1,000,000 gallon fuel oil storage tank; a new water tank; and other associated support equipment.

Combustion Turbine Unit 4 will be permitted to operate 2,500 hours per year while firing low sulfur fuel oil (0.05 percent sulfur). Water injection into the combustion area will be practiced for NO_X control.

The Department has determined that BACT for NO_X is 42.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmvd @15% O_2) under the very special circumstances of this project including location, lack of natural gas supply, low annual emissions for the project, installation of a single unit, etc. This limit will be achieved by water injection. Future increases in hours of operation will require installation of a selective catalytic reduction (SCR).

Emissions of carbon monoxide (CO), PM/PM_{10}, sulfuric acid mist (SAM), sulfur dioxide (SO_2), and VOC will be minimized by the efficient, high-temperature combustion of low sulfur fuel oil. A BACT determination was not required for CO, SAM, SO_2, or VOC.

KEYS' estimates of maximum potential annual emissions from Combustion Turbine Unit 4 are summarized in the following table. Actual emissions will be substantially less than estimated because much of the operation will be under low load conditions. For example, KEYS estimates that if it actually operates the unit for 2,500 hours per year, emissions will actually be less than 60 tons per year of NO_X considering low load versus the estimate of 95 given below.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	34	100	No
Pb	0.013	0.6	No
NO_X	95	40	Yes
PM/PM_{10}	31/31	25/15	Yes
SO_2	30	40	No
SAM	<7	7	No
VOC	7	40	No

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 (i.e. PSD Class II Areas) Therefore; multi-source modeling was not required for ambient air quality standards Class II increments.

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southeast District Office
400 North Congress Avenue
West Palm Beach, FL 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

Dept. of Environmental Protection
South District Branch Office
2796 Overseas Highway, Suite 221
Marathon, Florida 33050
Telephone: 305/289-2310

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Program Administrator, South Permitting Section, Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/Air/permitting/construction/stockisland.htm

PERMITTEE:

Keys Energy Services
1001 James Street
Key West, Florida 33401-6100

ARMS Permit No.	0870003-007-AC
PSD Permit No.	PSD-FL-348
SIC No.	4911
Expires:	July 31, 2007

Authorized Representative:
Daniel Cassel
Director of Generation

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality. The proposed project authorizes the installation of one nominal 48 megawatts, fuel oil-fired, simple cycle combustion turbine-electrical generator. This project additionally authorizes the installation of a nominal 1,000,000 gallon fuel oil storage tank and an additional water tank.

The project will be located at the Stock Island Power Plant near Key West, Monroe County. The physical address of the facility is 6900 Front Street, Stock Island. UTM coordinates for this facility are Zone 17; 425.65 km E; 2716.67 km N.

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 40 CFR 52.21. 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.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD Best Available Control Technology (BACT) Determination
Appendix GC General Conditions

Michael G. Cooke, Director
Division of Air Resource Management

Date:

FACILITY DESCRIPTION

The existing Stock Island Plant consists of two nominal 8.8 MW diesel generators, one nominal 23.5 MW simple cycle combustion turbine, two nominal 19.8 MW simple cycle combustion turbines and miscellaneous unregulated units. The proposed project is to install one nominal 48 MW simple cycle combustion turbine-electrical generator, one nominal 1,000,000 gallon fuel oil storage tank, and a water tank.

NEW EMISSIONS UNITS

The proposed project will result in the following new emissions units.

EU ID No.	Emissions Unit Description
011	General Electric LM 6000 PC SPRINT Combustion Turbine-Electrical Generator
012	One nominal 1,000,000 gallon Distillate Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

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

Title IV Acid Rain: This facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: This facility is a Title V major source of air pollution.

PSD Major Source: The project is located in an area designated as "attainment," "maintenance," or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is not one of the 28 PSD source categories, and is subject to the PSD applicability threshold of 250 tons per year. Potential emissions of at least one regulated pollutant exceed 250 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS Sources: The combustion turbine specified in this permit is also subject to regulation under the New Source Performance Standards for Stationary Gas Turbines, 40 CFR 60, Subpart GG and may be subject to Proposed Subpart KKKK.

NESHAP: The National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart YYYY for combustion turbines does not apply because the facility is not a major source of HAPS.

RELEVANT DOCUMENTS

- Air Construction/PSD Permit application received on October 14, 2004;
- First Department Request for Additional Information (RAI) dated November 10, 2004;
- Response to First RAI received on January 18, 2005;
- Supplement to First RAI Response received on February 18, 2005;
- Second Department RAI dated February 17, 2005;
- Response to Second RAI received on April 13, 2005; and
- Intent to Issue Air Construction/PSD Permit distributed May 23, 2005.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.
2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the South District Office, Florida Department of Environmental Protection, 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-3381. The phone number is 239/332-6975 and the fax number is 239/332-6969.
3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code.
4. General Conditions: The owner and operator are subject to, and shall operate under the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated 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 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified.
7. Permit Expiration: 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, and 62-210.300(1), F.A.C]
8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C.]
9. 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.]
10. Modifications: No emissions unit or facility subject to this permit 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.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. 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 Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. COMBUSTION TURBINE (EU 011) WATER INJECTION ONLY & ≤ 2,500 HOURS

This section of the permit addresses the following new emissions unit for the period during which the unit operates for 2,500 hours or less on a rolling 12-month total and with water injection only. Upon reaching the first rolling 12-month total of 2,501, section III.B. of this permit will supercede all conditions in this section(III.A.).

E.U. ID No.	Common Emission Unit Description
011	General Electric LM 6000 PC Sprint Combustion Turbine-Electrical Generator

Applicable Standards and Regulations

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for nitrogen oxides (NO_X), and particulate matter (PM_{10}). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (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 GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (c) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** The Department has made a preliminary determination subject to approval by EPA, that this regulation proposed on January 18, 2005 does not apply to this project.

Performance Restrictions

3. Combustion Turbine: The permittee is authorized to install, tune, operate and maintain one simple cycle combustion turbine-electrical generator with spray intercooling and water injection (General Electric Model LM6000 PC SPRINT). The unit is designed to produce approximately 48 MW of electrical power at ISO conditions. [Applicant Request]

4. Permitted Capacity: The heat input to the combustion turbine from firing No. 2 fuel oil shall not exceed 434 MMBtu per hour (LHV) based on the following: 100% base load, lower heating value of No. 2 fuel oil, and a compressor inlet air temperature of 41° F. 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. Heat input rates will vary depending upon compressor conditions and the combustion turbine characteristics. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves on file with the Department.
   [Design, Rule 62-210.200, F.A.C. (Definition - PTE)]

5. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle conversion which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. [Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.] (See III.B. for BACT if increased hours of operation.)

6. Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)]

{Permitting note: Pipeline natural gas is currently unavailable to the Keys.}

7. Hours of Operation: The combustion turbine shall operate no more than 2,500 hours based on a 12-month rolling total without installing a selective catalytic reduction (SCR) system. Exceeding this restriction shall require the installation and operation of an SCR system as required in III.B. [Applicant Request, Rules 62-210.200, (PTE) and 62-212.400(2)(g), F.A.C.]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

9. 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 the 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.]

EMISSIONS CONTROLS

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

11. Water Injection Technology: The permittee shall install, calibrate, tune, operate, and maintain a water injection system designed to achieve the permitted NO_x emissions standards for the unit. [Applicant request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

12. Future Selective Catalytic Reduction (SCR): The permittee shall design and build the project to facilitate and not to hamper or preclude the future installation of the SCR system. The combustion turbine may operate without the use of the SCR system for an initial period during which the total

hours of operation do not exceed 2,500 during any 12-month rolling total. [Design and Rule 62-212.400, F.A.C.]

13. 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.]

EMISSIONS STANDARDS

14. Summary: The following table summarizes the emissions standards for each pollutant and total emissions in lb/hr and TPY for informational and convenience purposes (PTE) only, and shall not be considered permit limits. This table does not supersede any of the terms or conditions of this permit.

Pollutant	Emission Standard/Limit	Emissions (lb/hr)	Emissions (TPY)
NO_X	42 ppmvd @ 15% O_2	75.9	94.9
CO	30 ppmvd @ 15% O_2	33.0	41.0
SO_2	0.05 percent sulfur fuel oil	23.6	29.5
SAM	0.05 percent sulfur fuel oil	5.4	6.8
PM/PM_{10}	VE = 10% as surrogate	25.0 (front and back)	31.3
PM/PM_{10}	VE = 10% as surrogate	13.9 (front half)	17.4
VOC	16 ppmvd @ 15% O_2	10.0	12.6

Note: Annual emissions, for the purposes of this table only, are based on a 41° F temperature and 2,500 hours of full load operation.

15. Carbon Monoxide (CO):

CO emissions from the combustion turbine shall not exceed 30.0 ppmvd @15% O_2. CO emissions shall not exceed 33.0 pounds per hour. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with EPA Method 10 and the requirements of this permit.
[Rule 62-212.400, F.A.C. (PSD Avoidance)]

16. Nitrogen Oxides (NO_X):

This emissions limit applies during the initial phase of operation when the combustion turbine operates no more than 2,500 hours based on a 12-month rolling total:

NO_X emissions from the combustion turbine shall not exceed a BACT emission limit of 42 ppmvd @15% O_2 during initial and annual tests nor exceed 42.0 ppmvd @15% O_2 on a 24-hour block average while firing fuel oil. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with 40 CFR Part 60 Subpart GG and based on a 24-hour block average for data collected from the continuous emissions monitor.
[Rule 62-212.400, F.A.C. (BACT)]

{Permitting note: Pipeline natural gas is currently unavailable to the Keys. However, for a similar unit operating on natural gas and for a comparable number of hours, a BACT limit would likely be set at 15 ppmvd @ 15% O_2.}

17. Particulate Matter (PM/PM_{10}) and Visible Emissions (VE)

Emissions of PM and PM_{10} shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. Visible emissions from the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM10 emission limits. [Rules 62-4.070(3) and 62-212.400, F.A.C. (PSD Applicability)]

18. Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

Emissions of SAM and SO_2 shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. SAM and SO_2 emissions shall not exceed 6.8 and 29.5 tons per year, respectively. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the fuel records specified by this permit.[Rules 62-4.070(3), and 62-212.400, F.A.C. (BACT)].

19. Volatile Organic Compounds (VOC):

VOC emissions from the combustion turbine shall not exceed 16.0 ppmvd corrected to 15% oxygen for each fuel. VOC emissions shall not exceed 10.0 pounds per hour. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting initial tests in accordance with EPA Methods 25 and/or 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Section III.A. of this permit. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

20. Definitions

(a) *Excess Emissions* are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

(b) *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(246), F.A.C.]

(c) *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]

(d) *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(160), F.A.C.]

21. Startup, Shutdown, Malfunction: 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 case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A written report summarizing each malfunction resulting in excess emissions shall be submitted in a quarterly report. [Rule 62-210.700(1) and (6), F.A.C.]

(a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for more than 2 hours in any 24-hour block averaging period. [Design; Rule 62-210.700(1) and (5), F.A.C.]

(b) During all startups, shutdowns, and malfunctions, the NO_x continuous emissions monitoring System (CEMS) shall monitor and record emissions. Up to 2 hours (120 minutes) of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. However, only data obtained during startups, shutdowns, and documented malfunctions may be used for the 2 hour exclusion period. Other arbitrary high readings may not be excluded from compliance averaging periods. [Rule 62-210.700(1) and (5), F.A.C.]

(c) A documented malfunction means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile, or electronic mail. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

22. Prohibition: 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. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

23. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. [Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

24. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

(a) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources;

(b) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources;

(c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines; and

(d) EPA Method 25 or 25A - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions).

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure specified in Rule 62-297.620, F.A.C.

25. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial NSPS performance tests and at least 15 days prior to any other required tests. [40 CFR 60.7, 40 CFR 60.8 and Rule 62-297.310(7)(a)9., F.A.C.]

26. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NO_X, VOC, and visible emissions. Initial NO_X performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and shall also be converted into units of the NSPS emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.]

27. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X, CO, and visible emissions from the combustion turbine for each fuel. If conducted at permitted capacity, NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). In the event that the operation of the CT is less than 400 hours per year, annual testing is not required for that year. [Rule 62-297.310(7)(a), F.A.C.]

28. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NO_X, and visible emissions from the combustion turbine. VOC emission tests are not required prior to permit renewal provided the CO emission standards are met. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. [Rule 62-297.310(7)(a)3., F.A.C.]

29. Tests After Major Repairs or Replacements: The Department may require that additional compliance testing be conducted within 90 days after major repairs or replacements are performed. [Rule 62-297.310(7)(a)4., F.A.C.]

30. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

31. 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.]

32. Applicable Test Procedures

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. [Rule 62-297.310(4)(a)1., F.A.C.]

2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)2., F.A.C.]

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

(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)(d), F.A.C.]

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

(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)(b), F.A.C.]

34. 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.]

CONTINUOUS MONITORING REQUIREMENTS

35. NO_X CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NO_X and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NO_X monitoring devices shall comply with the

requirements of 40 CFR 60.334(b) for 40 CFR Part 75 monitoring systems. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location. [Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

36. NO_X CEMS Data Requirements:

(a) Installation. The CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and 40 CFR 60.334(b).

(b) 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. A valid hour is one in which at least 1 data point is recorded in each quadrant during which the unit was operating.

(c) Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (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. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition 41 of this permit.

(d) Data Exclusion. As provided in III.A. 21-22., valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit. Up to 2 hours of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-297.520, F.A.C and 40 CFR 60.7].

37. Hours of Operation: Using a component of the gas turbine control system, the permittee shall monitor and record the hours of gas turbine operation. Within five working days following the end of each calendar month, the permittee shall record the total hours of operation (including hours during startups, shutdowns, and malfunctions) for the current month, and the total hours of operation for the current month plus the preceding 11 months.
[Rule 62-204.070, F.A.C., and Applicant Request]

COMPLIANCE DEMONSTRATIONS

38. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 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.]

39. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits for fuel oil specified in this permit by maintaining records required by 40 CFR 60.334 and 60.335. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

40. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of operation and amount of fuel fired for the combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. All hours of operation (including hours during startups, shutdowns, and malfunctions) shall be included in the demonstration of compliance with the 12-month fuel usage limitations. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

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

42. Excess Emissions Reporting:

(a) If excess NO_X or visible emissions 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) NSPS Semi-Annual Reports. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. 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 to the Compliance Authority.

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

(c) SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NOx emissions in excess of the BACT permit standards at Specific Condition 16 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.

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

43. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours 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.]

44. Hours of Operation: Within ten working days following the first consecutive 12-month period in which the hours of operation exceed 2,500, the permittee shall notify the Compliance Authority. The notification shall include a summary of operation for the last 12 months, and the expected date of initial operation of the SCR system for the control of NO_X as required by III.B. [Rule 62-204.070, F.A.C., and Applicant Request]

B. COMBUSTION TURBINE (EU 011) WATER INJECTION AND SCR & > 2,500 HOURS

This section of the permit addresses the following new emissions unit upon exceeding 2,500 hours or operation on a 12-month rolling total and thereafter. Upon exceeding 2,500 hours, the provisions of III.B. superceed III.A. for the rest of the operating life of the unit. BACT is water injection and SCR.

E.U. ID NO.	COMMON EMISSION UNIT DESCRIPTION
011	General Electric LM 6000 PC Sprint Combustion Turbine-Electrical Generator

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for nitrogen oxides (NO_X), and particulate matter (PM_{10}). Practicably enforceable limits have been established for sulfur dioxide (SO_2), and sulfuric acid mist (SAM) to avoid BACT determinations for these pollutants. [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (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

   (d) **Subpart GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (e) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** The Department has made a preliminary determination, subject to approval by EPA, that this regulation proposed on January 18, 2005 does not apply to this project.

PERFORMANCE RESTRICTIONS

3. Combustion Turbine: The permittee is authorized to install, tune, operate and maintain one simple cycle combustion turbine-electrical generator with spray intercooling and water injection (General Electric Model LM6000 PC SPRINT). The unit is designed to produce approximately 48 MW of electrical power at ISO conditions. [Applicant Request]

4. Permitted Capacity: The heat input to the combustion turbine from firing No. 2 fuel oil shall not exceed 434 MMBtu per hour (LHV) based on the following: 100% base load, lower heating value of No. 2 fuel oil, and a compressor inlet air temperature of 41° F. If different from the information provided in accordance with Specific Condition III.A.4, 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. Heat input rates will vary depending upon compressor conditions and the combustion turbine characteristics. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves on file with the Department.
   [Design, Rule 62-210.200, F.A.C. (Definition - PTE)]

5. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle operation which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. [Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.]

6. Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. Total fuel usage shall no exceed 13,600,000 gallons of fuel oil during any consecutive 12 months. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)].

7. Hours of Operation: The combustion turbine may operate 8,760 hours per year. [Applicant Request, Rule 62-210.200, F.A.C. (PTE)]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

9. 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 the 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.]

EMISSIONS CONTROLS

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

11. Water Injection Technology: The permittee shall install, calibrate, tune, operate, and maintain a water injection system designed to achieve the permitted NO_x emissions standards for the unit in conjunction with the SCR system.
[Applicant request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

12. Selective Catalytic Reduction (SCR): Within two months after exceeding the 12-month rolling total of 2,500 operating hours, the permittee shall install, calibrate, tune operate and maintain an SCR system designed to achieve the permitted NOx emissions standards for the unit in conjunction with the water injection system. [Design and Rule 62-212.400, F.A.C.]

13. 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.]

EMISSIONS STANDARDS

14. Summary: The following table summarizes the emissions standards for each pollutant and total emissions in lb/hr and TPY for informational and convenience purposes (PTE) only and shall not be considered permit limits. This table does not supersede any of the terms or conditions of this permit.

Pollutant	Emission Standard/Limit	Emissions (lb/hr)	Emissions (TPY)
NO_X	9 ppmvd @ 15% O_2 24-hr block average	16.3	36.0
CO	20.0 ppmvd @ 15% O_2	20.0	44.2
SO_2	0.05 percent sulfur fuel oil	23.6	39.9
SAM	0.05 percent sulfur fuel oil	5.4	6.9
PM/PM_{10}	VE = 10% as surrogate 0.05 percent sulfur fuel oil	25.0	109.5
PM	VE = 10% as surrogate 0.05 percent sulfur fuel oil	25.0	109.5
VOC	8.0 ppmvd @ 15% O_2	5.0	11.0

Note: Annual emissions, for the purposes of this table only, are based on an ambient temperatures and the equivalent of 4,420 hour of full load operation. PM/PM_{10} estimates are based on the equivalent of 8,760 hours of full load operation.

15. Carbon Monoxide (CO):

CO emissions from the combustion turbine shall not exceed 20.0 ppmvd @15% O_2. CO emissions shall not exceed 20.0 lbs per hour. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with EPA Method 10 and the requirements of this permit. [Rule 62-212.400, F.A.C. (PSD Avoidance)]

16. Nitrogen Oxides (NO_X):

The combustion turbine and SCR system shall be designed and constructed to meet an emission limit of 5.0 ppmvd @15% O_2. This shall be demonstrated during each initial test following installation of new catalyst. During normal operation, NO_x emissions shall not exceed 9.0 ppmvd @15% O_2 on a 24-hour block average. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with 40 CFR Part 60 Subpart GG and based on a 24-hour block average for data collected from the continuous emissions monitor.
[Rule 62-212.400, F.A.C. (BACT)]

{Permitting note: The 5.0 ppmvd value reflects BACT. The 9.0 ppmvd value is based on the fuel use limitation that would limit NO_x emissions to less than 40 tons per year. The Department will revise the higher long term limit downward in conjunction with any future applications that will increase fuel use above 13,600,000 gallons per year.}

17. Ammonia (NH_3)

The ammonia slip rate shall be limited to 10.0 ppmvd @ 15% O_2.
[Rule 62-212.400, F.A.C. (BACT).

18. Particulate Matter (PM/PM_{10})

Emissions of PM and PM_{10} shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. Visible emissions from the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM_{10} emission limits. [Rule 62-212.400, F.A.C. (PSD Applicability)]

19. Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

Emissions of SAM, and SO_2 shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. SAM and SO_2 emissions shall not exceed 6.9 and 39.9 tons per year, respectively. Compliance with the SO_2 limit provides assurance that SAM emissions stay within permitted limits. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the records specified by this permit. [Rule 62-212.400, F.A.C. (BACT)].

20. Volatile Organic Compounds (VOC):

VOC emissions from the combustion turbine shall not exceed 8.0 ppmvd corrected to 15% oxygen for each fuel. VOC emissions shall not exceed 5.0 pounds per hour. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting initial tests in accordance with EPA Methods 25 and/or 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Section III.B. of this permit. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

21. Definitions

(a) *Excess Emissions* are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

(b) *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(246), F.A.C.]

(c) *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]

(d) *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(160), F.A.C.]

22. Startup, Shutdown, Malfunction: 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 case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A written report summarizing each malfunction resulting in excess emissions shall be submitted in a quarterly report. [Rule 62-210.700(1) and (6), F.A.C.]

    (a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for more than 2 hours in any 24-hour block averaging period.
    [Design; Rule 62-210.700(1) and (5), F.A.C.]

    (b) During all startups, shutdowns, and malfunctions, the NO_x continuous emissions monitoring System (CEMS) shall monitor and record emissions. Up to 2 hours (120 minutes) of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. However, only data obtained during startups, shutdowns, and documented malfunctions may be used for the 2 hour exclusion period. Other arbitrary high readings may not be excluded from compliance averaging periods. [Rule 62-210.700(1) and (5), F.A.C.]

    (c) A documented malfunction means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile, or electronic mail. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
    [Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

23. Prohibition: 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. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

24. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. KEYS shall advise the Department of any requirements within the cited rule that would be incompatible with the operation of an SCR system or unadvisable due to storm design criteria. [Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

25. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

    (a) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources;

    (b) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources;

    (c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines.

    (d) EPA Method 25 or 25A

(e) - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions); and

(f) Conditional Test Method 027 – Measurement of Ammonia Slip.

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure specified in Rule 62-297.620, F.A.C.

26. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial NSPS performance tests and at least 15 days prior to any other required tests. [40 CFR 60.7, 40 CFR 60.8 and Rule 62-297.310(7)(a)9., F.A.C.]

27. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NO_X, VOC, ammonia slip and visible emissions. Initial NO_X performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and shall also be converted into units of the NSPS emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.]

28. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X, CO, and visible emissions from the combustion turbine for each fuel. Testing for ammonia slip is required during the first scheduled annual performance tests after the cumulative hours of operation exceed 1,500 actual hours starting from the initial installation of the SCR catalyst. Thereafter, ammonia testing is required during the first scheduled annual performance tests after subsequent cumulative 1,500 hours of operation or after regeneration, replacement or addition to the SCR catalyst system. If conducted at permitted capacity, NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). In the event that the operation of the CT is less than 400 hours per year, annual testing is not required for that year. [Rule 62-297.310(7)(a), F.A.C.]

29. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NO_X, and visible emissions from the combustion turbine. VOC emission tests are not required prior to permit renewal provided the CO emission standards are met. Testing for ammonia slip meeting the requirements of Condition 26, Annual Performance Tests will meet the requirements of this condition. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. [Rule 62-297.310(7)(a)3., F.A.C.]

30. Tests After Major Repairs or Replacements: The Department may require that additional compliance testing be conducted within 90 days after major repairs or replacements are performed. [Rule 62-297.310(7)(a)4., F.A.C.]

31. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100

percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

32. 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.]

33. Applicable Test Procedures

    (a) Required Sampling Time.

        1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. [Rule 62-297.310(4)(a)1., F.A.C.]

        2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)2., F.A.C.]

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

    (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)(d), F.A.C.]

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

    (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)(b), F.A.C.]

35. 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.]

CONTINUOUS MONITORING REQUIREMENTS

36. NO$_X$ CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NO$_X$ and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NO$_X$ monitoring devices shall comply with the requirements of 40 CFR 60.334(b) for 40 CFR Part 75 monitoring systems. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location. [Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

37. NO$_X$ CEMS Data Requirements:

(a) Installation. The CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and 40 CFR 60.334(b).

(b) 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. A valid hour is one in which at least 1 data point is recorded in each quadrant during which the unit was operating.

(c) Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (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. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition 42 of this permit.

(d) Data Exclusion. As provided in III.B. 21-22, valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit. Up to 2 hours of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-297.520, F.A.C and 40 CFR 60.7].

38. Hours of Operation: Using a component of the gas turbine control system, the permittee shall monitor and record the hours of gas turbine operation. Within five working days following the end of each calendar month, the permittee shall record the total hours of operation (including startups, shutdowns, and malfunctions) for the current month, and the total hours of operation for the current

month plus the preceding 11 months.
[Rule 62-204.070, F.A.C., and Applicant Request]

COMPLIANCE DEMONSTRATIONS

39. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 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.]

40. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits for fuel oil specified in this permit by maintaining records required by 40 CFR 60.334 and 60.335 and the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

41. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of operation and amount of each fuel fired for the combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. All hours of operation shall be included in the demonstration of compliance with the 12-month fuel usage limitations. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

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

43. Excess Emissions Reporting:

    (a) If excess NO_X or visible emissions 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) NSPS Semi-Annual Reports. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. 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 to the Compliance Authority.

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

    (c) SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NOx emissions in excess of the BACT permit standards at Specific Condition 16 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.

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

44. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual fuel usage 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.]

DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
012	One distillate fuel oil storage tank for Combustion Turbine Unit 4 (approximately 1.0 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: As revised October 15, 2003, NSPS Subpart K does not apply to storage vessels which store a liquid with a vapor pressure less than 3.5 kPa.

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 1.0 million gallon distillate fuel oil storage tank designed to provide low sulfur fuel oil to Combustion Turbine Unit 4 or any other units on the site. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

   {Note: Emissions of VOC form this unit are estimated to be less than one ton per year.}

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.]

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT proposal discussed in the Technical Evaluation for this project for the rationale regarding the following BACT determination.

For operation less than 2,500 hours, the following BACT determination applies:

a. NO_x, - 42.0 ppm @ 15% O_2 (75.9 lb/hr) while firing oil.

Continuous compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS and based on a 24-hr block average. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

b. PM/PM_{10} - distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight, and visible emissions ≤ 10% opacity, based on a 6-minute average.

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

c. The mass emission rate standards are based on a turbine inlet condition of 41° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

For operation 2,500 hours or greater, the following BACT determination applies:

a. NOx - 5 ppm @ 15% O_2 (8.9 lb/hr) while firing oil.

Compliance with the NO_x standards shall be demonstrated by conducting tests in accordance with EPA Method 7E or Method 20. Tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

d. PM/PM_{10} - distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight, and visible emissions ≤ 10% opacity, based on a 6-minute average.

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

b. The mass emission rate standards are based on a turbine inlet condition of 41° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By:	Approved By:
Trina L. Vielhauer, Chief Bureau of Air Regulation	Michael G. Cooke, Director Division of Air Resources Management
Date	Date

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.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Keys Energy Services
Stock Island Power Plant
Combustion Turbine Unit 4

48-Megawatt Simple Cycle Power Project

Monroe County

DEP File No. 0870007-AC (PSD-FL-348)

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

May 31, 2005

1. APPLICATION INFORMATION

Applicant Name and Address

Keys Energy Services
1001 James Street
Post Office Box 6100
Key West, Florida 33041-6100

Authorized Representative:
Daniel Cassel, Director of Generation

Processing Schedule

- Received Air Construction Permit/PSD application on October 14, 2004;
- Additional information requested November 10, 2004 and February 17, 2005;
- Received additional information on January 18, February 18, and April 13, 2005; and
- Intent to Issue Air Construction/PSD Permit distributed April 22, 2005.

Facility Description and Location

Keys Energy Services (KEYS) operates the Stock Island Power Plant, which is located at 6900 Front Street, Stock Island near Key West in Monroe County. The existing Stock Island Plant consists of two nominal 8.8 MW diesel generators, one nominal 23.5 MW simple cycle combustion turbine, two nominal 19.8 MW simple cycle combustion turbines and miscellaneous unregulated units. The location of the Stock Island Power Plant is shown in Figures 1 and 2.

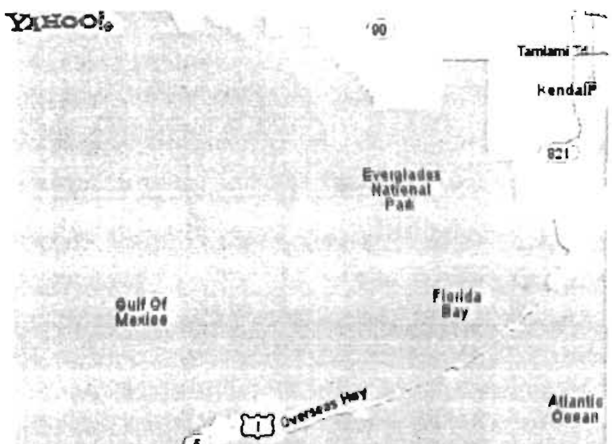


Figure 1. Location of Key West

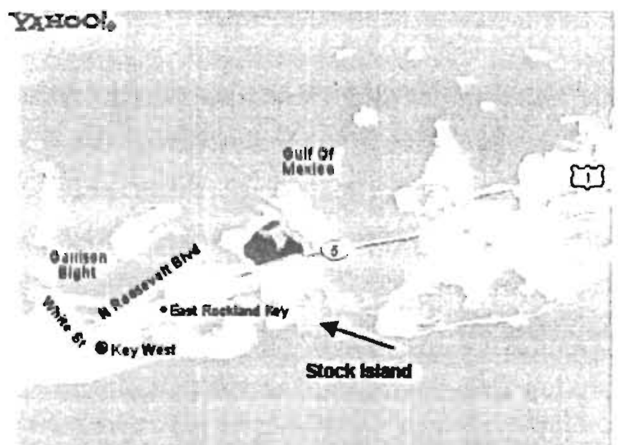


Figure 2. Location of Stock Island

The Stock Island Power Plant is located approximately 90 kilometers southwest from the Class I Everglades National Park.

Regulatory Categories

Title III: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

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

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

PSD: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is a Major Facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The facility is not a steam electrical generating plant and is not subject to the power plant siting provisions of Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a fuel oil-fired simple cycle unit consisting of the following equipment and specifications: one nominal 48 MW General Electric LM6000 PC SPRINT combustion turbine-electrical generator; a nominal 1 million gallon diesel fuel storage tank; a new water tank; and a minimum 60-foot exhaust stack with associated ducting, flow straightening and silencing. Combustion turbines are often referred to as "gas turbines". This refers to use of air (instead of steam) as the operating medium and not firing with natural gas. The less ambiguous term, combustion turbine, will be used in this review. Following are further details.

- Fuel: There is no natural gas infrastructure in extreme South Florida. KEYS proposes to use low sulfur (0.05% Sulfur) distillate oil. The applicant's original request was for 4,420 fuel equivalent hours of operation. The application has since been revised to request 2,500 hours per year of operation.
- Generating Capacity: The proposed combustion turbine has a nominal generating capacity of 48 MW. The actual range is approximately 40 to 50 MW for temperatures between 90 and 40 degrees (°F). This range is related to the higher density and mass flow of the working medium (air) at lower temperatures.
- Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of distillate oil at relatively high temperatures. Emissions of SAM and SO_2 will also be minimized by firing low sulfur distillate oil. NO_X emissions will be reduced by water injection into the combustor.

- Continuous Monitors: The combustion turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitor will be employed for demonstration of continuous compliance with the Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: The following summarizes the exhaust characteristics at 41 °F:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
No. 2 Fuel Oil	433.4 mmBtu/hour	41° F	~814° F	~555,000

Project Description

Refer to Figure 3 below.[1] A combustion turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 5 stage low pressure compressor (LPC) of the GE LM6000 PC SPRINT combustion turbine proposed for this project. The air is further compressed in the 14-stage high pressure compressor (HPC) to a pressure ratio of about 30 times atmospheric pressure. A portion of the compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 30 replaceable fuel nozzles.

The hot combustion gases are then diluted with additional cool air from the compressor and directed to the two-stage high pressure turbine (HPT) section and then the 5-stage low pressure turbine section. The power turbine is directly driven.

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 is discharged at a temperature range of 760 to 860 °F and high excess oxygen and is normally available for additional energy recovery (such as in combined cycle configurations).

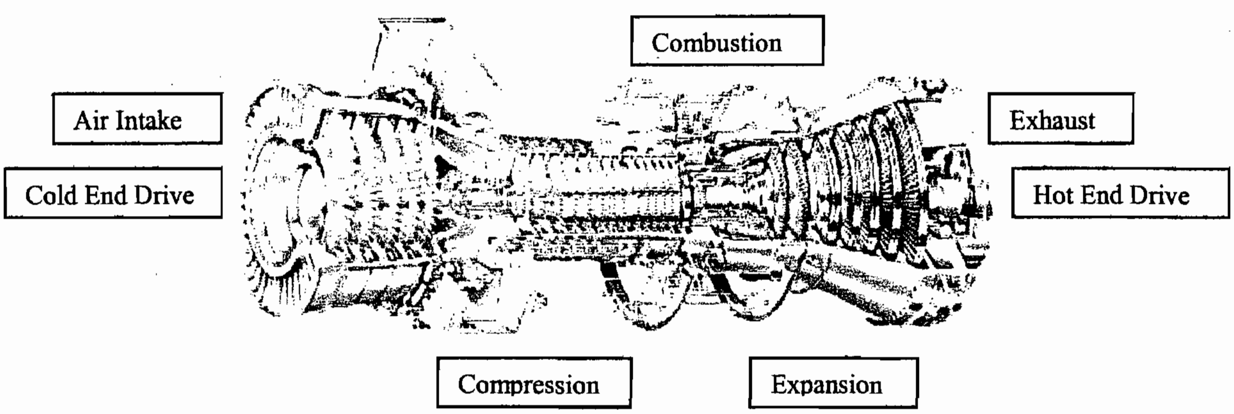


Figure 3. Key Components of the LM 6000 Simple Cycle Combustion Turbine

The particular model selected by the applicant has some very specific features including:

- Water Injection. This feature involves water injection into the combustor for the purpose of NO_X abatement. Greater power production is also realized by the additional mass flow.
- SPRay INTercooling (SPRINT™): This additional feature, known as the Sprint™ System, involves injecting fine water droplets into the LPC and HPC inlet plenums. This provides for better cooling of hot section components and allows higher firing temperatures to be realized in the combustor. This feature increases shaft power by approximately 12 percent (%) at 59 °F and 30% at 90 °F compared to a gas-fired LM 6000 PC practicing water injection.

Further process details are provided in the Draft determination of Best Available Control Technology (BACT) in Section 4.0 below.

<u>Potential Emissions</u>

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds. The following table summarizes the applicant's original (and revised) estimate of the annual emissions in tons per year from the proposed project.

Table 1. Applicant's Original (and Revised) Estimated Annual Emissions

Pollutant	Project Emissions TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
CO	34 (21)	100	No
Pb	0.013	0.6	No
NO_X	154 (76)	40	Yes
PM/PM_{10}	110 (31)	15/25	Yes
SO_2	48 (24)	40	Yes (No)
SAM	15 (<7)	7	Yes (No)
VOC	10 (6)	40	No

3. RULE APPLICABILITY

<u>State Regulations</u>

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 Florida Administrative Code.

Chapter	**Description**
62-4	Permitting Requirements
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution

Chapter	Description
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

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.

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
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

Note: Acid rain requirements will be included in the Title V air operation permit.

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined 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. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) listed in Table 62-212.400-2, F.A.C. For each significant pollutant exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project as originally proposed are required for NO_X, SO_2, SAM and PM/PM_{10}. Based on the revised application, determinations are required for NO_X, and PM/PM_{10}

The other part of 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 – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Rule 62-210.200 (definitions), FAC as follows:

"Best Available Control Technology" or "BACT" - 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 energy, environmental and economic impacts, and other costs, 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.

a. *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.*

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

According to Rule 62-212.400(5)(h), FAC, the applicant must at a minimum provide certain information in the application including:

3. *A detailed description of the system of continuous emissions reduction proposed by the facility or modification as BACT, emissions estimates and any other information as necessary to determine that BACT would be applied to the facility or modification;*

According to Rule 62-212.400(6), FAC, in making the BACT determination, the Department shall give consideration to:

1. *Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).*
2. *All scientific, engineering, and technical material and other information available to the Department.*
3. *The emission limiting standards or BACT determinations of any other state.*
4. *The social and economic impact of the application of such technology.*

4.2 NO_X BACT Determination

4.2.1 Nitrogen Oxides Formation

Nitrogen oxides form in the combustion turbine process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

In most 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.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation is depicted in Figure 4 which is from a General Electric discussion on these principles.

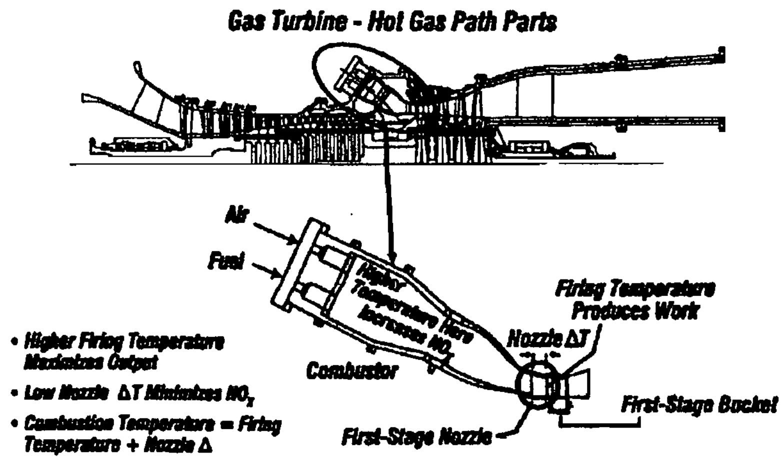


Figure 4 – Relation between Flame Temperature and Firing Temperature

Fuel NO_X is formed when fuels containing bound nitrogen are burned.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 400 ppmvd @15% O_2 for a fuel oil-fired LM 6000 PC SPRINT combustion turbine (200 ppmvd for gas-firing).[2] The proposed NO_X controls will reduce these emissions significantly.

For reference, the New Source Performance Standard (40 CFR 60, Subpart GG) for NO_X emissions from large utility gas turbines such as the GE7FA is approximately 120 ppmvd @15%O_2. This standard, applicable to combustion turbines built after 1977, constitutes the legal floor (absolute maximum NO_X value) in a "Top/Down" BACT determination.

More recently EPA proposed a new standard (40 CFR 60, Subpart KKKK) applicable to combustion turbines that commence construction <u>after</u> February 18, 2005. Proposed Subpart KKKK limits NO_X emissions from large fuel oil-fired combustion turbines to 1.2 pounds NO_X per megawatt-hour (lb/MWH). This equates to approximately 34 ppmvd @15% O_2.[3]

KEYS provided a letter to support their position that KEYS commenced construction on February 18, 2005 such that Subpart KKKK does not apply to the proposed project.[4] Notwithstanding the apparent agreement, the Department must consider the Subpart KKKK proposal in setting a BACT determination for this project, if it is not an applicable requirement.

4.2.2 Descriptions of Available NO_X Controls

Wet Injection

Fuel and air are mixed within traditional combustors and the combustion actually occurs on the boundaries of the flame. This is termed "diffusion flame" combustion. 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 achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 90% for oil firing. GE does not presently guarantee emissions less than 42 ppmvd when firing fuel oil in an LM6000.

Carbon monoxide (CO) and hydrocarbon (HC) 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 Emissions (DLE)

Lean fuel combustion provides a theoretically lower flame temperature. Premixing of the air and fuel prior to entering the combustor 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 GE product for aeroderivative combustion turbines is called Dry Low Emissions (DLE). The features of the early DLE combustion system are shown in Figure 5. In contrast to other low emissions technologies, the lean pre-mix feature of the DLE combustor for aeroderivative engines functions even at low load. As previously mentioned, without DLE or water injection, NO_X would be approximately 200 and 400 ppmvd @15% O_2 on gas and oil respectively.

The first commercial installation of the DLE combustion system was on a 43 MW LM6000 gas fired combustion turbine in the mid-1990's at the Ghent power station in Belgium. It achieved emissions of 16 ppm NO_X, 6 ppm CO and 1 ppm unburnt hydrocarbons.

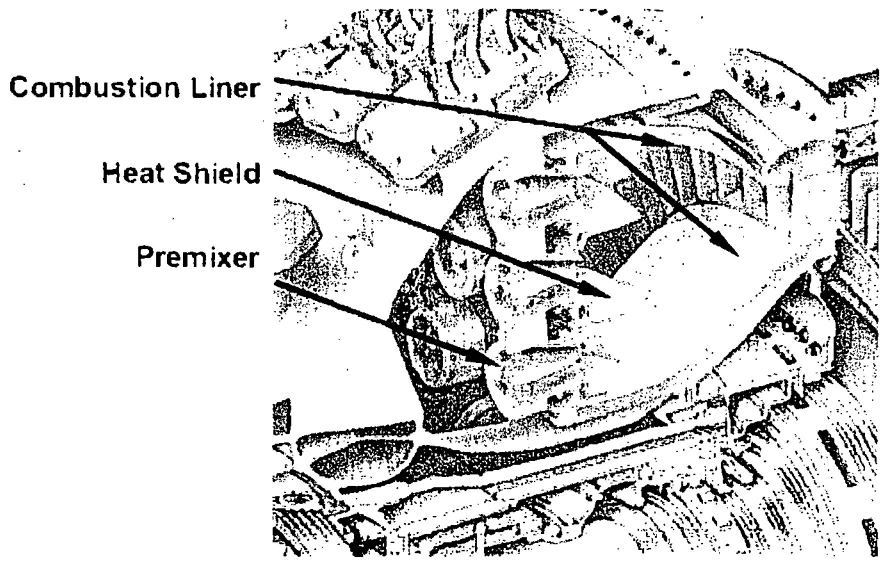


Figure 5 – Dry Low Emissions (DLE) Combustor

Orange Cogen installed two LM6000 PB combustion turbines in the mid-1990's to operate in combined cycle. Initially the units were required to achieve 25 ppmvd NO_X @15% O_2 while firing natural gas with a requirement to reduce emissions to 15 ppmvd several years after startup. Following is the time series developed from the most recent data available from the continuous emission monitoring record submitted quarterly by Orange CoGen to EPA. The values greater than 15 ppmvd are typically short-duration startups that are actually characterized by low mass (lb/hr) emissions during the given hours. The 15 ppmvd NO_x limits for these units are based on 3-hr averaging times, therefore it appears that they are meeting their permitted limits.

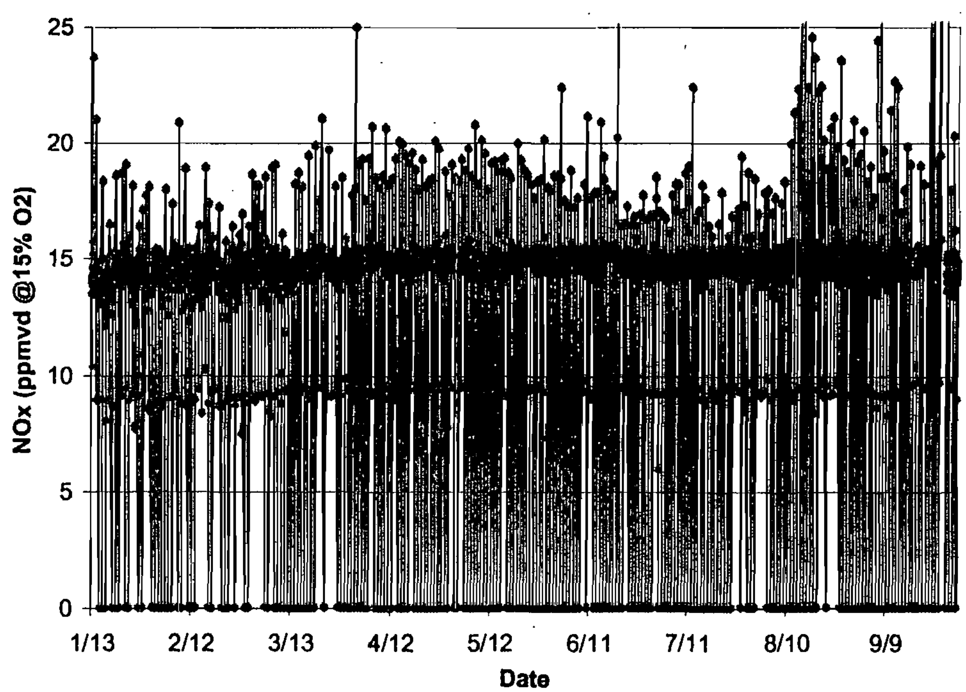


Figure 6 – NO_X Emissions from Orange CoGen LM6000 PB Gas-Fired Unit 1 (2004)

The DLE arrangement installed at Orange CoGen is not available on newer versions of LM 6000 combustion turbine. There is a newer version called DLE-II technology that is available on newer LM6000 PC and LM6000 PC SPRINT combustion turbines. According to GE sales and technical experts, the DLE-II is available with a 15 ppmvd guarantee while operating on natural gas.[5]

The DLE-II was designed to operate in conjunction with the higher power features of the newer versions of the LM 6000 PC and PC SPRINT. This was made possible by dispensing of a shroud in the combustion area that previously required cooling. The lower cooling requirement makes it possible to divert more air from the compressor to make a leaner air-fuel mixture for combustion.

DLE and DLN technologies are technically possible for oil-fired units. However they are more expensive and it is more difficult to reach the values achievable by DLN or DLE when using gas. According to the Siemens-Westinghouse website, their 45 MW SGT-800 combustion turbine (formerly ABB GTX100) with their 3rd generation DLE combustor can meet 25 ppmvd @15% O_2 when burning fuel oil.[6] It is not certain whether this is accomplished by wet injection or by the DLE feature.

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.[7] 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™.[8] 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.[9] By now, 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.[10] 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 yet available for fuel oil-fired combustion turbines of the size of an LM 6000 PC SPRINT.

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.

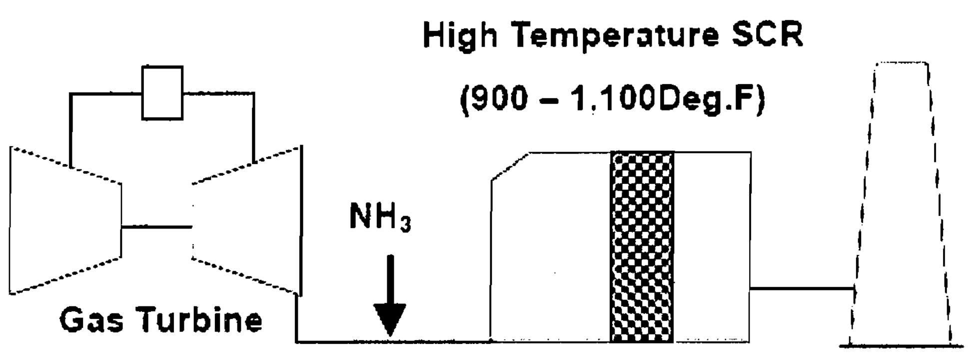


Figure 7 – High Temperature SCR Configuration for Simple Cycle Combustion Turbine

SCR technology has progressed considerably over the last decade. Zeolite catalyst was developed for high temperature applications. Such catalyst provided by Engelhard was involved in a failed application at the oil-fired simple cycle PREPA Cambalache project in Puerto Rico in the late 1990's. The permitted limit while firing fuel oil in the three nominal 83 MW ABB GT-11N was 9 ppmvd.[11]

There has been much debate regarding the reasons for the failure ranging from the use of fuel oil, its sulfur content of 0.15%, the nature of high temperature applications, water injection, the catalyst, etc. EPA allowed removal of the catalyst from the simple cycle units and installation of Low NO_X burners on some boilers located at the same facility to abate the NO_X increase. It is important to note that the permit application was submitted 11 years ago and improvements have since been made in high temperature SCR catalysts.

All of the catalyst suppliers presently offer formulations and strategies for applications for the moderate temperature range (760 – 860 °F) of SCR applications suitable for the LM6000 PC SPRINT. Hitachi offers a catalyst with a TiO_2 base and tungsten (WO_3) that Hitachi claims outperformed zeolite catalyst in accelerated durability tests.[12] The peak activity temperature (842 °F) for Hitachi's catalyst is virtually equal to the exhaust temperatures expected from the LM6000 PC SPRINT at full load. This temperature is less than experienced by the catalyst at the PREPA Plant (824 to 1014 °F).

The following figure reflects Hitachi's view of its high temperature TiO_2/WO_3 formulation compared with conventional low/middle temperature V catalyst and high temperature zeolite catalyst.

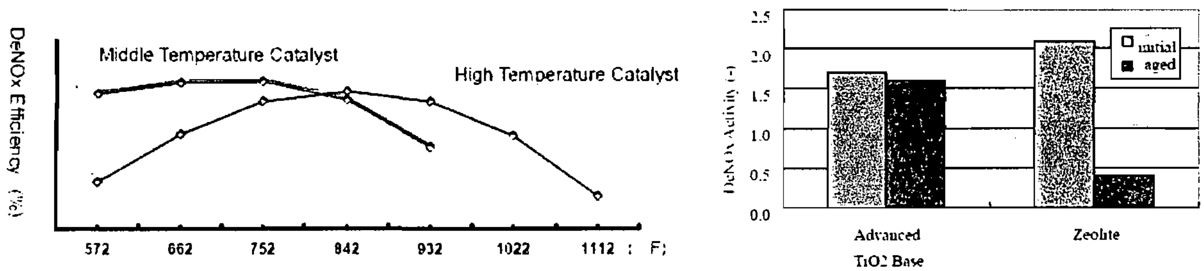


Figure 8 – High Temp TiO_2/WO_3 versus Mid-Temp V and High Temp Zeolite Catalysts

If this information is accurate, it certainly provides reason to believe that a possible cause is inherently shorter lifetime for zeolite formulations. According to Hitachi the accelerated zeolite deterioration observed during its durability tests was caused by the water concentration in exhaust gas that impacted the crystalline structure. Moisture in the flue gas would be the case for all fuel applications, especially when firing natural gas.

One implication of Hitachi's findings is that gas firing (had it been available at PREPA Cambalache) could have caused even faster deterioration of the zeolite catalyst than observed. Therefore the past problems with hot SCR and fuel oil firing are more likely related to the catalyst formulation than to the use of fuel oil.

One possible strategy is to cool the exhaust gas to match the peak activity point of the less expensive medium temperature V catalyst at about 700 °F. This can be done using tempering air supplied from a cooling air skid. This options allows use of more familiar catalyst formulations without ammonia oxidation.

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.

Fortunately sulfur is not a problem for the catalyst in high temperature and relatively low sulfur fuel applications (natural gas or distillate fuel oil) because the ammonium sulfate, bisulfate, sulfite deposits burn off at the high operating temperatures.

There are several examples of <u>conventional</u> SCR systems operating in Florida including:

- Kissimmee Utilities Authority Unit 3. 3.5 ppmvd NO_X on gas and 12 ppmvd on fuel oil.
- Progress Energy Hines Block 2. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- JEA Brandy Branch. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- TECO Bayside – seven combustion turbines. 3.5 ppmvd on gas.
- FP&L Manatee Unit 3. 2.5 ppmvd on gas and 10 ppmvd on fuel oil
- FP&L Martin Unit 8. 2.5 ppmvd on gas and 10 ppmvd on fuel oil.

There are several other approved projects now under construction in Florida that require conventional SCR systems. Most recently, DEP issued a permit for Turkey Point Unit 5 with NO_X limits of 2.0 ppmvd on gas and 8.0 ppmvd on fuel oil.

SCR has been installed in several dozen simple cycle gas-fired LM6000 combustion turbines and in a few fuel oil-fired units. Typical emissions limits are on the order of 2.5 to 5 ppmvd. SCR was also specified for the recently approved LM6000 PC SPRINT units to be installed at the City of Tallahassee Hopkins Plant. The guaranteed NO_X limits are 5 ppmvd whether burning gas or fuel oil.

SCONO$_X$^{TM}

This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power is 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 but in the exhaust of an LM6000 PC SPRINT combustion turbine.

SCONO$_X$^{TM} systems were installed at seven sites ranging in capacity from 5 to 43 MW.[13] None were installed at large facilities.

SCONO$_X$^{TM} technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx^{TM} has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx^{TM} systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, SCONO$_X$^{TM} 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.

The need for more cooling air (compared to SCR catalysts) to achieve the necessary temperature operating range and the requirement for natural gas or hydrogen for regeneration of the catalyst makes SCONO$_X$^{TM} infeasible for this project.

4.2.3 Applicant's Original NO_X BACT Proposal

The applicant originally proposed a BACT NO_X limit of 42 ppmvd @15% O_2 while operating 7000 hours per year and limiting annual fuel use to the equivalent of 4,420 hours per year. KEYS proposes to meet the proposed BACT emission limit by water injection.

The reader is referred to the KEYS application on-file with the Department and available on-line at the site given at the end of this review. In summary, the KEYS asserts that SCR is not technically or economically feasible for the following (paraphrased) reasons:

- SCR catalyst failed on an oil-fired simple cycle application at the PREPA project.
- There are insufficient hours of operation at other existing installations to conclude that SCR is reliable on oil-fired simple cycle units.
- The catalyst will have to be replaced every year.
- Any downtime is virtually unacceptable.
- The area is basically isolated and there are few power alternatives for the area especially if storms make power unavailable from the mainland.
- The marine environment and remote location drive up materials and construction costs.
- The overall cost per ton of NO_X removed is too high.
- The cost analysis submitted by the City of Tallahassee (who proposed SCR) contains errors.

4.2.4 Department's Draft NO_X BACT Determinations

A) Recent Test Data

Table 2 contains some information from a recent report prepared by the California Air Resources Board (CARB) to the Legislature regarding control technologies that reduce NOx emissions from gas-fired power plants.[14] All of the results appear to be on gas-fired LM 6000 combustion turbines. In all reported tests, NO_X emissions were less than 5 ppmvd. All but a few ammonia measurements were equally low. The one result listed in Table 3 for the New York Port Authority (NYPA) Hellgate plant is probably representative of the 11 new LM 6000 SPRINT combustion turbines known to be operated by the NYPA. According to a report prepared in 2003 for the NYPA, all of their units had no problems complying with the very strict NO_X limit of 2.5 ppmvd @15% O_2 during steady-state conditions.[15] However, during startup and shutdown these units often exceeded permit limits. This issue has since been resolved through a Consent Order and new permit limits for startup and shutdown periods.

Table 2. Test Results for LM 6000 Simple Cycle Combustion Turbine Projects

Project Location	Date	NO_X / NH_3 (ppmvd @ 15% O_2)	Comments
NYPA, Hellgate, NY	2001	1.7 – 2.2 / 3.4 - 14	Water Injection & SCR
Calpine Lambie, CA	1/2003	2.5 / 1.5	Water Injection & SCR
Calpine Creed, CA	1/2003	1.5 / 0.8	Water Injection & SCR
Calpine Goose, CA	1/2003	2.4 / 0.4	Water Injection & SCR
N. Cal., Lodi, CA	7/2000	2.8 / 25	Steam Injection & SCR
Wellhead, Huron, CA	3/20/2002	2.7 / 0.4	Water Injection & SCR
Gilroy Energy, CA	2002	3.3 – 3.6 / 0.9 – 1.5	Water or DLE & SCR
Palm Springs, CA	2001	3.8 – 4.5 / 2.2 – 4.2	Steam or Water & SCR
San Diego, CA	2001/02	3.4 – 4.6 / 1.3 - 37	Water Injection & SCR

B) Recent Determinations

Table 3 includes some recent BACT determinations in Florida and other states for LM6000 series combustion turbines as well as some Lowest Achievable Emission Rate determinations. All specify SCR. Some of the information is from the previously mentioned CARB report to the Legislature.

All of the listed determinations are for NO_X emission limits less than or equal to 5 ppmvd @15% O_2. Most are approximately 2.5 ppmvd @15% O_2. In 1999, CARB issued guidance establishing a maximum value of 5 ppmvd for Power Plant Siting and BACT in California for simple cycle units.[16].

Additional information was located in the report prepared in 2003 for the New York Port Authority (NYPA) mentioned above. The purpose of the report was to review the performance of the numerous LM6000 PC SPRINT installations recently installed by NYPA. The permitted limits were issued at a time when there was much less information about actual performance of these units than there is today.

Based on the list, the "Top" technology in a "Top/Down" determination is 2.0 ppmvd for natural gas fired units and approximately 5.0 ppmvd for fuel oil-fired units. The NO_X BACT limit proposal submitted by KEYS is significantly greater than the top technology. It cannot be accepted without showing that technical or economic considerations make significantly lower values infeasible.

Table 3. Recent NO_X Standards for LM 6000 Simple Cycle Combustion Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2 and Fuel	Comments
Tallahassee, FL	100	5 – NG/fuel oil (24-hr)	2xLM 6000 PC SPRINT (NH_3=10)
W. Springfield, MA	84	3.5 /6.0 – NG/Oil (1-hr)	2x42 MW LM6000 (NH_3 = 7.0/10)
Lowell, MA	96	2.0 – NG (1-hr)	2x48 MW LM6000 (NH_3 =2.0)
Wallingford, CT	225	2.5 – NG (1-hr)	5x45 MW LM6000 (NH_3 = 6.0)
Shoreham, L. Island	~95	9 – fuel oil (1-hr)	2xLM 6000 (NH_3 = 10)
NYPA Hellgate	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA Harlem River	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA N. 1st St.	47	2.5 – NG (1-hr)	1x47 MW LM6000 SPRINT CTs
NYPA 23rd St/3rd Ave	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA Vernon Blvd.	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA Pouch Term.	47	2.5 – NG (1-hr)	1x47 MW LM6000 SPRINT CTs
NYPA Brentwood	47	2.5 – NG (1-hr)	1x47 MW LM6000 SPRINT CTs
Calpine Lambie, CA	50	2.5 – NG (3-hr)	1x49.9 MW LM6000 PC SPRINT
Calpine Creed, CA	50	2.5 – NG (3-hr)	1x49.9 MW LM6000 PC SPRINT
Calpine Goose, CA	50	2.5 – NG (3-hr)	1x49.9 MW LM6000 PC SPRINT

Table 3 (Cont.) Recent NO_X Standards for LM 6000 Simple Cycle Combustion Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2 and Fuel	Comments
Modesto Ripon, CA	95	2.5 – NG (3-hr)	2x47.5 MW LM6000 PC SPRINT
Lodi Energy, CA	50	3.0 – NG (3-hr)	1x49.6 MW LM6000 PC SPRINT
Herndon, CA	50	3.0 – NG (3-hr)	1x49.6 MW LM6000 PC SPRINT
N. Cal., Lodi, CA	49	3.0 – NG (3-hr)	1x49 MW LM6000 PC SPRINT
Wellhead, Huron, CA	45	3.5 – NG (3-hr)	1x45.4 MW LM6000 CTs
E.I. Colton, CA	48	3.5 – NG (3-hr)	1x48 MW LM6000 SPRINT
Gilroy Energy, CA	135	5 – NG (1-hr)	3x45 MW LM6000 PC
Palm Springs, CA	135	5 – NG (3-hr)	3x45 MW LM6000 SPRINT
Carson Energy, CA	42	5 – NG (3-hr)	1x42 MW LM6000 (started 1995)

It is noted that most if not all of the units listed in Tables 2 and 3 employ water or steam injection instead of DLE in conjunction with SCR. This means that gas-fired units are similar to the fuel oil-fired LM 6000 combustion turbines in regard to the employment of wet injection techniques and the purpose of SCR for further control.

i) Results for Shoreham Oil Fired LM 6000 Units

Long Island Power Authority (LIPA) supplies the fuel for, and Pennsylvania Power & Light (PPL) operates, the Shoreham Plant on Long Island, New York. The plant is one of several small installations sited at key locations throughout Long Island to meet escalating demand. There are two fuel oil-fired LM6000 combustion turbines at the Shoreham Plant.

For reference, Long Island is also characterized by a marine environment. The weather can be very cold and severe in the winter requiring heating of fuel or measures to insure the temperature of SCR catalyst is maintained at an optimal value.

The permit issued for the Shoreham Plant is a non-PSD permit with a short-term NO_X limit of 9 ppmvd @15% O_2 on a 1-hour basis and an annual limit of 22.5 tons between the two units. There is an NH_3 limit of 10 ppmvd @15% O_2 on a 1-hour basis. The permit requires both NO_X and NH_3 continuous emission monitoring systems (CEMS). NO_X emissions are controlled by water injection and SCR. Each unit has a 110-foot stack. The units started up in June 2002.

The Department downloaded 2003 CEMS NO_X data submitted by PPL from the EPA Air Markets Website. They operate in intermittent duty and never operate an entire 24-hour period in a day.

Figure 9 is the time series for August 2003 for both units. It includes all valid hours during which at least 0.25 hours of data were recorded. For the most part, emissions were in the range of 3 to 8 ppmvd @15% O_2. The peak value observed was 23 ppmvd and occurred during an hour that included a startup and only 0.32 hours of operation. Only 7.5 pounds of NO_X were emitted that entire hour.

According to PPL's filings with the Securities and Exchange Commission, the SCR system was provided by Deltak, L.L.C. The Department does not have information regarding the catalyst supplier used by Deltak.

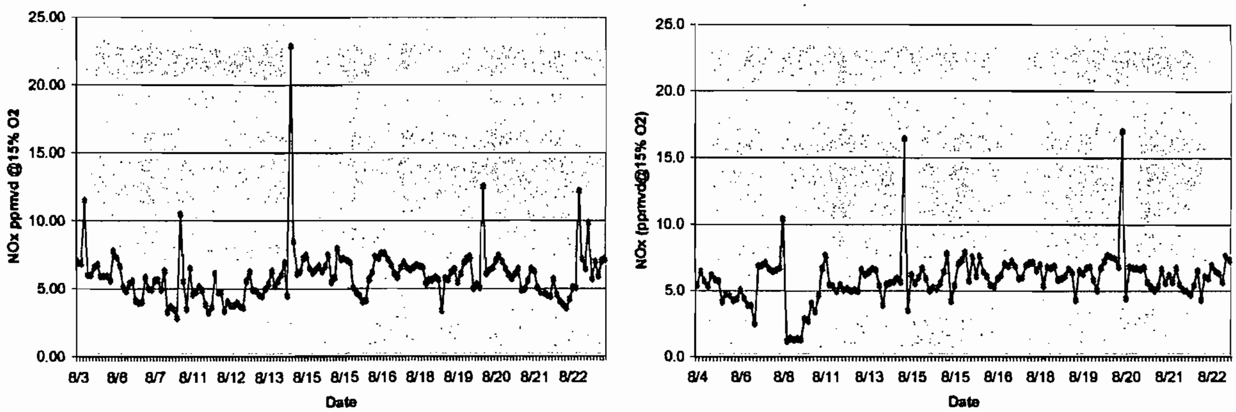


Figure 9 – NO_X Emissions - PPL Shoreham LM6000 Oil-Fired CTG-1&2 (August 2003)

ii) West Springfield Gas and Oil-Fired Project

The Consolidated Edison West Springfield Redevelopment Project is located in Massachusetts. It consists of two 42 MW GE LM6000 combustion turbines with water injection and SCR for NO_X control. Initially the project was permitted to fire natural gas only.

The initial BACT NO_X limit for the West Springfield Project (final approval June 9' 2003) was 2.5 ppmvd @15% O_2 and ammonia slip of 2.5 ppmvd NH_3 @15% O_2. The new units were initially not able to achieve the specified BACT limits during transient or steady-state conditions. Since that time, a new limit of 3.5 ppmvd @15% O_2 while burning gas has been set.

Massachusetts DEP approved use of ultralow sulfur fuel oil (< 0.0030 % sulfur) in November 2003 and allowed an increase in use of gas and fuel oil in July 2004.

Table 4 is a listing of the permit conditions applicable to the West Springfield Project. Table 5 summarizes the fuel use limitations for the two units.[17] Table 6 is a summary of operating hours and NO_X emissions since the units started operation in 2002 until the end of the third quarter of 2004. The information was accessed from the EPA Air Markets Website. The total NO_X emissions are 20.5 tons combined for the two units since they started up in 2002.

Table 4. Emissions Limits for two LM6000 Combustion Turbines at W. Springfield

Pollutant	Natural Gas		Oil (Ultra Low Sulfur)		Mass Emission Limits
	ppmvd @15% O_2	lb/hr (each CTG)	ppmvd @15% O_2	lb/hr (each CTG)	tpy (3) (both CTGs combined)
PM(2)	n/a	4.5	n/a	11.3	14.7
SO_2(4)	0.4	0.9	0.7	1.5	2.9
NO_X	3.5	5.9	6.0	10.8	19.3
CO	5.0(5) / 10.0(6)	4.3	5.0(5) / 10.0(6)	1.0	27.7
VOC	2.0	1.1	12.0	6.4	7.4
SAM	n/a	0.15	n/a	0.2	0.3
NH_3	7.0	4.4	10	6.2	10.6 (7)
Opacity	≤ 5 percent(8)		≤ 20percent(8)		

Table 5. Fuel Use Limits for two LM6000 Combustion Turbines at W. Springfield

Combustion Units	Natural Gas		Oil (Ultra Low Sulfur)	
	cubic feet/mon (1)	cubic feet/yr (2)	gallons/mon (1)	gallons/year (2)
CT-1 & CT-2	344,174,400	3,019,640,000	2,455,731 (3)	5,828,607 (3)

(1) Calendar Month
(2) Based on a rolling 12-month total
(3) Assuming natural gas heating value of 1000 Btu/ft^3 and oil heating value of 140,000 Btu/gallon.
(3) For every gallon of oil fired, the natural gas allowance (per calendar month or per rolling 12-month total) shall be reduced by 359.4 cubic feet.

Table 6. Hours and NO_X Emissions from W. Springfield LM6000 CTs (2002-2004)

Unit/year	Hours	Heat Input	NO_X (lb/mmBtu)	NO_X (TPY)
CTG1/2004	291	87540	0.09	1.70
CTG2/2004	209	64180	0.11	1.40
CTG1/2003	674	211206	0.04	1.90
CTG2/2003	388	112371	0.11	1.90
CTG1/2002	652	228565	0.06	7.10
CTG2/2002	747	252897	0.05	6.50
Total/2002-04	**2961**	**956759**	**0.04**	**20.50**

Figure 10 is a time series for the dual fuel fired units, Units 1and 2, at West Springfield. The graph includes only the hours during which fuel oil was fired in 2004. Substantial firing after mid-year was primarily with natural gas due to the higher seasonal cost of fuel oil. The graphed values represent only discrete hours that are not necessarily contiguous. They do not include data when the unit operated for 15 minutes or less. This avoided inclusion of excluded data as "zeros". The high values in January apparently occurred during hours that contained both a startup and a shutdowns. The others occurred at very low load (< 8 MW). Although the concentrations appear to be high, the impact on annual emissions is minimal.

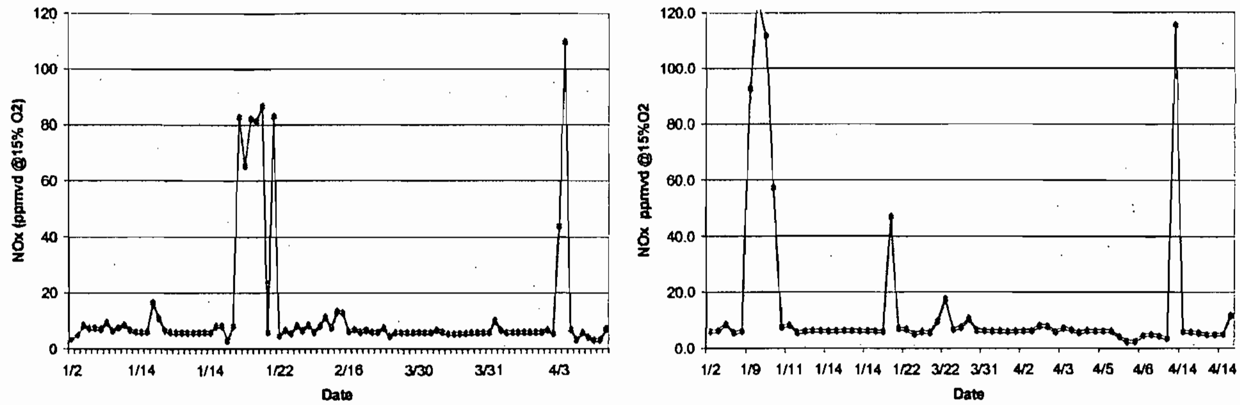


Figure 10 – NO_X Emissions - W. Springfield LM6000 Dual Fuel Units 1&2 (Oil, 2004)

The SCR systems were provided by Peerless and used Haldor Topsoe catalyst. The precise catalyst formulation is not yet known by the Department. It is certainly not zeolite and is believed to be a titanium and tungsten formulation. A Department representative visited with representatives of Haldor Topsoe at the 2004 Power Gen Conference.[18] They showed the Department representative startup curves for one of the West Springfield combustion turbines while firing oil. According to the curves, startup was accomplished within 10 minutes after which NO_X emissions were less than 5 ppmvd and at times approached 2 ppmvd @15% O_2.

Department personnel contacted the Massachusetts DEP. Their representatives stated that the West Springfield Project has not had any problems meeting the new limits of 6 ppmvd while burning natural gas and 10 ppmvd @15% O_2 while burning fuel oil.[19] The Department also contacted a representative of Consolidated Edison who said they have had no problems so far and there has been no sign of catalyst degradation.[20]

iii) FPL Bayswater - Pratt& Whitney Oil and Gas Fired Projects

Bayswater consists of two projects built by FPL in the area of Far Rockaway, Queens, New York. It is adjacent to the existing Keyspan Generating Facility. The first of the two FPL projects was called Bayswater and the second was called Jamaica Bay. They are treated as a single facility called Bayswater under the EPA Acid Rain Program. Following is a picture of the two FPL projects and the separate Keyspan facility.

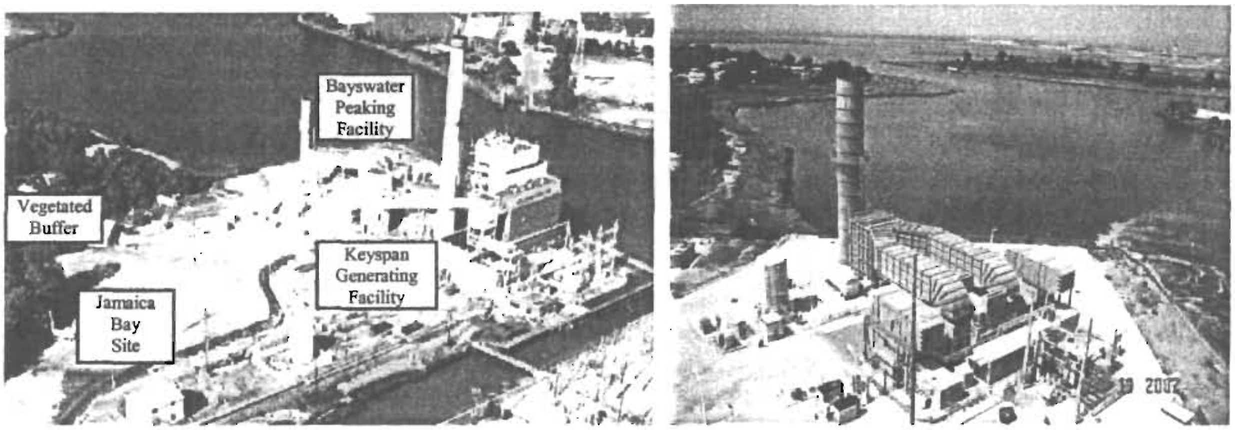


Figure 11 – FPL Bayswater Projects. Two Dual Fuel Pratt & Whitney Swift-Pac Sets

The Bayswater facility is comprised of two simple cycle dual fuel 54 MW Pratt & Whitney FT-8 Swift-Pacs. Each Swift-Pac consists of two small combustion turbines, "pantleg" ducting, a single electrical generator and stack. The primary fuel for the Bayswater Project is natural gas. The primary fuel for the Jamaica Bay project is fuel oil.

According to the Project Environmental Assessment, the NO_X emission limits proposed for the Jamaica Bay project (the second of the two) were 2.5 ppmvd and 6.0 ppmvd @15% O_2 for gas and oil respectively.[21] The annual emissions through the third quarter of 2004 for both projects are listed in the following table. The information source is the EPA Markets Website.

Table 7. Hours and NO_X Emissions from FPL Bayswater P&W CTs (2002-2004)

Unit/year	Hours	Heat Input	NO_X (lb/mmBtu)	NO_X (TPY)
Bayswater/2004	1,567	889,976	0.02	7.2
Jamaica Bay/2004	343	177,743	0.05	2.4
Bayswater/2004	1,210	675,991	0.05	14.5
Jamaica Bay/2003	517	286,020	0.07	7.1
Bayswater/2002	708	377,376	0.07	12.8
Total/2002-04	**4345**	**2,407,106**	**0.037**	**44.0**

Figure 12 is a time series for August 2004 for the two Bayswater units (i.e. Bayswater and Jamaica Bay). The graphed values represent all hours for which data were reported including startups and shutdowns. All high values occurred during partial hours of operations were related to startup. For the most part emissions were typically 5 ppmvd for the fuel oil-fired Jamaica Bay Unit (graph on left) and 2 ppmvd for the Bayswater Unit during steady state.

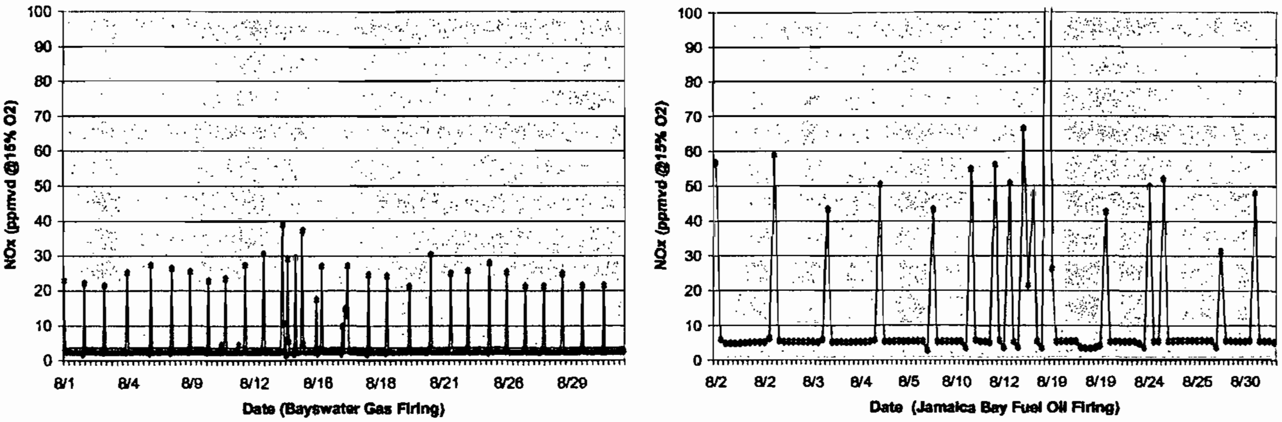


Figure 12 – NO_X Emissions from FPL Bayswater Gas and Oil-Fired Units (August, 2004)

The two plots are similar in that each indicates higher emissions during startup, representative of the water injection targets of 42 ppmvd for oil firing and 25 ppmvd for gas firing prior to enabling of the SCR systems. Although the concentrations are relatively high during each startup hour (usually a fraction of an hour), mass emissions are actually low.

Department personnel contacted a representative of Envirokinetics who supplied the SCR systems for both projects.[22] The gas-fired Bayswater project that started up in 2002 used a catalyst formulation known as Engelhard VNX-HT. According to Engelhard, it is designed for a temperature range of 600 to 875 °F with an optimum range between 800 and 850 °F. The catalyst has a relatively low vanadium (V) content and high titanium oxide (TiO_2). This is consistent with the nominal 840 °F exhaust temperature of the P&W Swift-Pac characteristics.

The fuel oil-fired Jamaica Bay project that started up in 2003 used a catalyst formulation known as Haldor-Topsoe DNX. Topsoe's formulations are typically tungsten (W) and TiO_2. This is consistent with the previous discussion regarding the Hitachi catalyst and operation at moderate to high temperature.

Both catalysts perform well based on the graphs shown above. In its research, the Department also found that the Haldor-Topsoe product has lower pressure drop characteristics, which means less power is lost.[23]

Department representatives contacted an operations expert of FPL Energy at the Bayswaters facility. He confirmed the details provided by Envirokinetics and Haldor-Topsoe. Among the key points were that the units are 98-99% reliable. Both comply with their respective NO_X emission standards.

The only concern expressed by the FPL representative about the use of SCR with fuel oil is an effect on the continuous emission monitoring system (CEMS) for ammonia. Apparently, small amounts of carbon build up in the sampling system. It is theorized that the carbon buildup causes adsorption of ammonia which can be subsequently released. The observation is that NH_3 levels appear to oscillate. No effect is seen on NO_X removal or the functioning of the catalyst. FPL is experimenting with changes to the NH_3 sampling system.

The Department concludes that this side-by-side comparison constitutes a good real-world experimental comparison of SCR for simple cycle gas firing with SCR for fuel oil-firing. Most factors other than the fuels and their delivery systems are equal. The results suggest that problems at previous simple cycle installations had less to do with inherent characteristics of fuel oil than they have to do with catalyst formulation.

iv) Hawkeye Greenport Long Island Oil-fired Project and Freeport Energy Gas-fired Project

In additional information submitted by KEYS, reference was made to "the failure of the catalyst at the Greenport Facility" on the far east side of Long Island. The Hawkeye (formerly Global) Greenport facility is a fuel oil-fired 50 MW P&W Swift-Pac Combustion Turbine set. The unit started up in 2003.

By its letter dated February 16, 2005 KEYS referred the Department to Mr. Tom Turner, President of Turner Envirologic, and the supplier of the SCR system installed at Hawkeye. Department representatives contacted Mr. Turner. He described the original catalyst as a zeolite formulation consistent with the failed product at the oil-fired PREPA simple cycle project. The zeolite catalyst at Hawkeye was replaced with a TiO_2 and W formulation consistent with the successful product at the FPL Bayswater units.

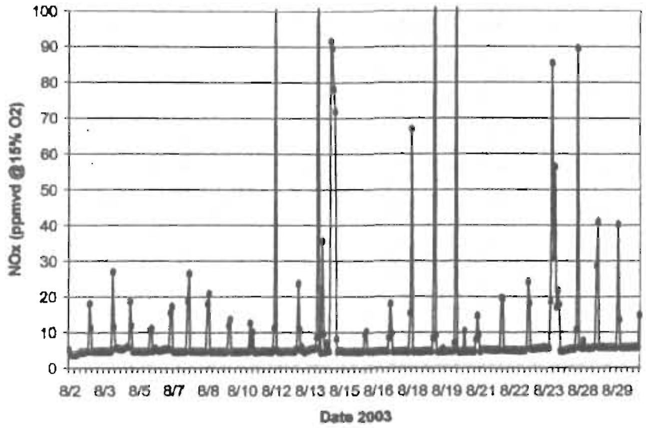
Mr. Turner added that his firm also supplied the SCR system on the 50 MW Freeport Energy facility that consists of a gas-fired GE LM6000 SPRINT combustion turbine. The same zeolite catalyst formulation was also replaced with the TiO_2 and W formulation previously described. His firm also oversaw the replacement of the catalyst at the gas-fired LM6000 for the City of Burbank with the Haldor-Topsoe formulation. He also supplied the SCR system for the 100 MW dual-fuel Larkspur, San Diego project that incorporates LM 6000 combustion turbines.

The following table is a summary of the operation of the Hawkeye Greenport oil-fired unit since its startup. The total annual and average NO_X emissions that include startups are low.

Table 8. Hours and NO_X Emissions from Hawkeye Greenport P&W CT (2003-2004)

Unit/year	Hours	Heat Input	NO_X (lb/mmBtu)	NO_X (TPY)
Hawkeye (Oil)/2004	699	333,809	0.04	4.3
Hawkeye (Oil)/2003	773	363,120	0.05	4.5
Total/2003-04	**1,472**	**696,929**	**0.026**	**8.9**

The lb/mmBtu entries for 2003 and 2004 based on the average of the individual hourly measurements. However the lb/mmBtu entry for the totals is less because the data are weighted by production. Basically the higher 2003 and 2004 values include partial hours such as startups that are characterized by greater lb/mmBtu (and ppmvd) values but lower lb/hr values. The time series for emissions from the Hawkeye Greenport oil-fired facility during August 2003 and August 2004 are displayed are displayed in Figure 13.



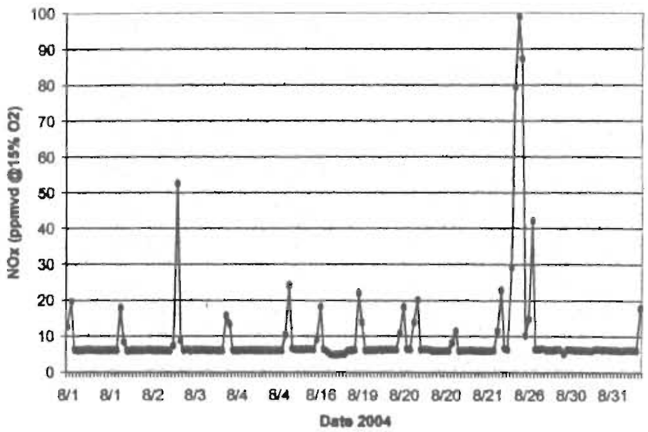
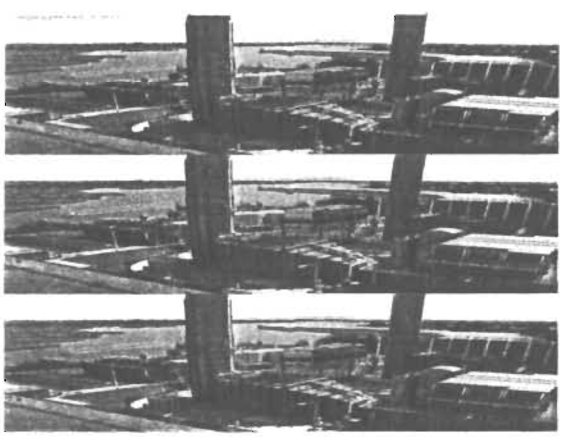


Figure 13 – NO_X Emissions - Hawkeye Greenport Oil-fired Units (Aug., 2003, 2004)

The difference between the two graphs is that startup emissions tended to be greater in 2003 than 2004. While the Department does not have the details regarding the alleged failure, it appears that steady-state emissions have been low. It is possible that the problems were related to very restrictive startup emission limits or problems maintaining low ammonia emissions.

As mentioned, Mr. Turner said that the Freeport gas-fired experienced similar problems. There are two LM6000 SPRINT units located at the site. One is owned by Freeport Energy. The other is owned by a merchant company affiliated with PPL. Following is the time series for the unit designated as Freeport for most recent months given in the EPA Air Markets Website.



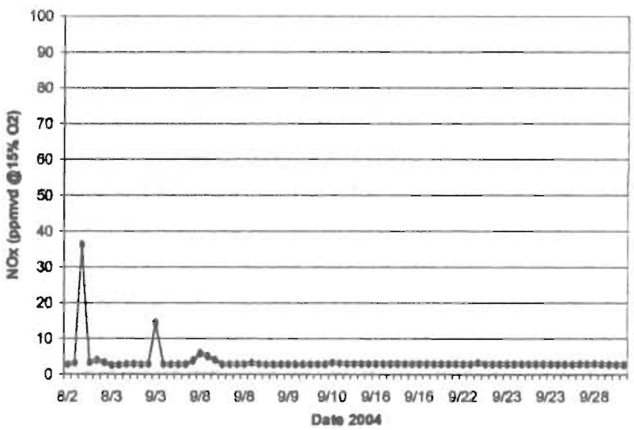


Figure 13 – Photo and NO_X Emissions – Freeport Energy Gas-fired Unit (Aug/Sept., 2004)

Emissions from the Freeport gas-fired LM6000 unit are clearly very low and meet the 2.5 ppmvd limits except during startup. In any case, the compelling facts are: both the fuel oil-fired and gas-fired unit referenced by Mr. Turner operate well now. The zeolite catalyst in each has been replaced with a formulation more appropriate for the application. The source, Mr. Turner, cited by KEYS does not believe fuel oil-firing was the cause of the alleged failures. In fact, he stated that the cause of the alleged failures was related to the zeolite catalyst for the particular conditions.

Mr. Turner's statements and the Department's conclusions are consistent with the observations by Hitachi about zeolite catalyst, the PREPA failure using zeolite catalyst, and the FPL Bayswater success using the Cormetech low V/TiO_2 and the Haldor-Topsoe TiO2/W formulations. This is not to suggest that zeolite catalysts are doomed to failure. They just need to be reformulated or cooled or used within the correct applications.

v) City of Tallahassee Fuel Oil and Gas-fired Project

The Department recently determined that SCR is cost-effective for a project by the City of Tallahassee (COT) to install two GE LM6000 PC SPRINT gas and fuel oil-fired combustion turbines. The project was permitted to operate 4,000 hours per year while firing fuel oil and 1,600 hours per year while firing natural gas. The BACT emission limit was determined to be 5 ppmvd @15% O_2 whether gas or fuel oil is used.

KEYS reviewed the application and determination for the COT project and claim numerous errors and flaws. The Department notes that the calculations submitted by COT actually represent “marginal” rather than average cost-effectiveness.

The higher marginal cost-effectiveness values (adding SCR to wet injection) would not change the conclusion. Conducting the analysis assuming baseline control to the NSPS value of approximately 110 ppmvd would also be cost-effective.

C. Cost-effectiveness of NO_X Control

Cost-effective values for the KEYS project were originally submitted in a response to a request by the Department for additional information and with the intent of the unit to be operated almost continually for a total of 4,420 fuel equivalent hours. The Department is in disagreement with KEYS with respect to several items included in this original analysis. The following summarizes the major issues of which the Department is in disagreement.

The Department believes that the KEYS total direct costs estimate (weighted from several bids) is somewhat high because of a bid by GE Energy. The GE bid is likely high due to the fact that this company would have used one of the other suppliers, added an additional charge, and not actually supply the same duration guarantee as the underlying bidders.

Cost-effective values supplied by KEYS are also high because of the inclusion of a 20 percent ($626,000) contingency. EPA believes the contingency should be 3%. In any event, since KEYS has decided to use GE as the overall project supplier, the contingency for the SCR system will be absorbed into the total LM6000 project contingency that is surely less than 20%.

The cost of an annual catalyst change ($383,000) is unreasonable because the bidders will guarantee the catalyst lifetime or pay a pro-rated replacement cost. The annual replacement assumption alone adds about $2,000 of cost per ton of NO_X removed.

The claimed cost ($353,000) of power lost during an annual catalyst change-out is also unreasonable. EPA excluded this term in its own review. Even if such costs were allowed, correction for a change-out every three years would lower the cost-effectiveness value by nearly another $2,000 per ton. Additionally, the Department believes that the change would not take one week, but rather 2 to 4 days. Most likely such a change out can be timed to other scheduled outage that occur in terms of several years rather than every year.

An interest rate of 7% is assumed. While EPA uses the concept of the “social” interest rate, it is not a practical term. The actual interest rate for a non-taxable utility for bonds maturing over a period of 15 years is lower. However at this time, the difference between the social interest rate and the real interest rate for FMPA is not great. It is noted that claims to use social interest rates can establish a precedent that makes it difficult to use the real interest rates on subsequent projects when the rates increase.

Rather than point out other differences in opinion, it is sufficient to state that with a few corrections, the *marginal* cost of NO_X control is cost-effective for the original intended operation of 4.420 equivalent hours of operation. For example, EPA Region 4 estimated the cost-effectiveness at $6,120 which would be cost-effective whether it is on a marginal or an average basis. The *average* cost, had it been provided by KEYS and reviewed by the Department and EPA, would easily be cost-effective.

Table 9 is an updated cost-effectiveness analysis submitted by KEYS. It includes estimates of *average* cost-effectiveness for NO_X control by water injection and by a combination of water injection and SCR. It also includes an estimate of the *marginal* cost-effectiveness between the two strategies. The analyses were based on their revised request of 2,500 hours of operation per year instead of continuous operation and the "fuel equivalent" of 4,420 hours per year of operation.

As stated earlier, the Department is in disagreement with several key points regarding the cost effectiveness estimates supplied by the applicant. The analysis presented in Table 9, although revised to reflect the newly requested 2,500 operating hours, remains unchanged in regard to the Department's concerns. Though these estimates are believed to be relatively high, the data is useful in demonstrating some important concepts.

The vast disparity between marginal vs average costs should be noted. Clearly even with operation limited to 2,500 hours, SCR is cost effective from an *average* standpoint. Based on the KEYS estimate however, from a *marginal* standpoint, SCR appears to be less cost effective.

It should also be noted that the cost effectiveness presented in this table was based on a reduction from approximately 87 tons per year to 10 TPY. In actuality, prior to reaching 2,500 operating hours, the unit will be producing 60 TPY or less, thus making the reduction even less cost effective ($22,000/ton). Compound this with the fact that once SCR is in place, the unit need only remain under 40 TPY to avoid PSD applicability. In this case, the cost effectiveness from a *marginal* standpoint of the reduction from 60 to 40 TPY begins to reach extreme proportions ($54,000/ton). These estimates are based on projected fuel usage and equivalent operating hours supplied by KEYS and presented in Table 10.

Other circumstances unique to this project that have been considered by the Department include the following:

- The KEYS project is unique in that it is located on an island, virtually isolated from the mainland, but for a single highway. This isolation adds to the cost and reliability of delivery of goods.
- In the event of a major hurricane strike, Keys residents most likely must rely on locally supplied power. The addition of this unit to the existing facility will ensure the needs of the residents will be met during such an emergency.
- The total project size is very small. It consists of only one 48 MW unit that will operate on a limited basis for at least the first few years following startup. According to projected fuel usage and equivalent operating hours submitted by KEYS, this unit is expected to operate for less than 2,000 equivalent full load hours during the first 4 years of operation.

The Department has concluded that based on marginal and average analysis, SCR is cost effective once 2,500 hours of operation has been reached and likely prior to that. However, taking into consideration the unique circumstances associated with this project, the Department will allow the applicant to defer the installation of SCR until the unit reaches 2,500 hours of annual operation, when it is obviously cost effective from both a marginal and an average standpoint.

Table 9. Average and Marginal Cost-Effectiveness for NO_X Control Options

	WI Alone Average C.E.	WI + Plus SCR Average C.E.	WI + SCR vs WI Marginal C.E.
	Dollars	Dollars	Dollars
Total Direct Cost (DC)	**$477,018**	**$3,606,018**	**$3,129,000**
Indirect Capital Cost			
Contingency	$95,000	$721,000	$626,000
Engineering & Supervision	$48,000	$361,000	$313,000
Construction & Field Exp.	$24,000	$180,000	$156,000
Construction Fee	$48,000	$361,000	$313,000
Startup Assistance	$10,000	$73,000	$63,000
Performance Test	$5,000	$36,000	$31,000
Total Indirect Cap. Cost	**$230,000**	**$1,732,000**	**$1,502,000**
Installed Costs	**707,018**	**5,338,018**	**4,631,000**
-SCR Catalyst Cost		-$317,000	-$317,000
Total Capital Investment (TCI)	**$707,018**	**$5,021,018**	**$4,314,000**
Direct Annual Costs	Dollars	Dollars	Dollars
Catalyst Replacement		$145,182	$145,182
Operating & Maintenance	$13,000	$83,000	$70,000
Water Usage	$184,500	$184,500	
Reagent Feed (Ammonia/Water)		$27,985	$27,985
Power Consumption	$3,703	$24,056	$20,353
Lost Power Generation			
Water Injection Equipment	$-592,500	$-592,500	
Backpressure		$63,320	$63,320
Catalyst Replacement		$48,661	$48,661
Increased Fuel Consumption	$136,649	$136,649	
Annual Distribution Check		$55,000	55,000
Total Direct Annual Costs	**$-254,648**	**$175,852**	**$430,501**
Indirect Annual Costs			
Overhead	$7,800	$49,800	$42,000
Administrative Charges	$14,140	$107,140	$93,000
Property Taxes			
Insurance	$7,070	$53,070	$46,000
Capital Recovery	$77,560	$551,560	$474,000
Total Indirect Annual Costs	**$106,570**	**$761,570**	**$655,000**
Total Annualized Costs	**$-148,078**	**$937,423**	**$1,085,501**
Annual Tons NOx Produced	**87.1**	**87.1**	**87.1**
Annual Tons NOx Not Produced or Removed	**533.1**	**609.8**	**76.8**
Annual Tons NOx Emitted	**87.1**	**10.4**	**10.4**
Cost Effectiveness ($/ton)	**$-278**	**$1,537**	**$14,134**

Table 10. Projected Fuel Usage and Equivalent Operating Hours

Year	Hours of Operation	Gallons Fuel Burned	Equivalent Full Load Hours	NOx Produced in Tons
2006	1,905	3,740,000	1,219	42.5
2007	2,259	4,436,000	1,446	50.4
2008	2,648	5,200,000	1,988	59.1
2009	3,107	6,100,000	2,282	69.3
2010	3,565	7,000,000	2,542	79.5
2011	3,972	7,800,000	2,770	88.6
2012	4,329	8,500,000	2,999	96.5
2013	4,685	9,200,000	3,295	104.5
2014	5,149	10,110,000	3,651	114.8

D. NO_X BACT Emission Limits

The Department will set a NO_X limit of 42 ppmvd @15% O_2 while firing oil and 15 ppmvd @ 15% O_2 while firing natural gas. Compliance with these limits must be demonstrated during an initial test and during annual tests thereafter. Compliance with the 15 ppm limit on gas will be required when natural gas becomes available to the Keys. These limits apply for the restricted operation of 2500 hours per year requested by the applicant.

If in the future there is a need to relax the requested restriction on hours, alternative limits would have to be met. The use of SCR and an emissions limit of 5.0 ppmvd value reflect BACT with operation greater than 2,500 hours. However a 9.0 ppmvd value based on the fuel use limitation requested in the original application would limit NO_x emissions to less than 40 tons per year. These limits for operation greater than 2,500 hours have been incorporated into the permit.

The Department would revise the higher long term limit downward in conjunction with any additional increases in fuel use. A continuous NO_x limit of 5 ppmvd @ 15% O_2 while firing fuel oil must be met at that time.

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

In the original application based on the use of 13,567,000 gallons per year (4,420 equivalent hours) of fuel oil No. 2, the potential of SO_2 and SAM emissions are reported as 47.8 TPY and 14.6 TPY respectively. This exceeds their significant emission rates of 40 TPY and 7 TPY requiring BACT determinations for both pollutants.

However, BACT determinations for SO_2 and SAM are not required based on the revised emission estimates (2,500 operating hours) submitted by KEYS. The revised potential emissions of SO_2 and SAM are 29.5 and 6.8 TPY respectively.

The applicant has indicated that if there is a future need to relax the requested restriction on hours (> 2,500), that they would take practicably enforceable limits of 39.9 TPY SO2 and 6.9 TPY SAM to avoid BACT determinations for these pollutants.

The following are the BACT analyses for SO_2 and SAM based on the use of 13,567,000 gallons per year (4,420 equivalent hours) of fuel oil No. 2 as presented in the original application.

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.

The applicant referred to a table in a Department of Energy analysis of the cost impact of a regulation requiring a complete replacement of the standard specification (0.05% S) highway diesel fuel by 0.0015% sulfur diesel by 2011.

A portion of the table is reproduced below.

Table E1. End-Use Prices and Total Supplies of Highway Diesel, 1999 and 2007-2015, Assuming 6-Percent Return on Investment

Analysis Case	1999	2007	2008	2009	2010	2011	2015	2007-2010 Average	2011-2015 Average
End-Use Prices of Highway Diesel (1999 Cents per Gallon)[a]									
Reference (500 ppm)	114.0	121.6	122.3	123.0	123.6	124.1	124.3	122.6	124.3
Regulation (ULSD)	NA	128.6	129.0	129.5	130.4	131.3	129.4	129.4	129.7
Higher Capital Cost (ULSD)	NA	129.4	129.9	130.5	131.2	132.2	130.1	130.3	130.6
2/3 Revamp (ULSD)	NA	128.9	129.2	129.9	130.7	131.7	129.7	129.7	130.0
10% Downgrade (ULSD)	NA	129.0	129.4	129.9	130.8	133.2	130.0	129.8	130.7
4% Efficiency Loss (ULSD)	NA	128.6	129.0	129.5	130.5	131.4	129.6	129.4	130.0
1.9% Energy Loss (ULSD)	NA	128.9	129.3	129.6	130.5	131.5	129.5	129.6	129.8
Severe (ULSD)	NA	130.4	130.7	131.4	132.2	134.3	131.1	131.2	131.7
No Imports (ULSD)	NA	130.2	130.4	130.9	131.6	132.9	130.5	130.3	131.1
Total Highway Diesel Supplied (Million Barrels per Day)									
Reference									
Total (500 ppm)	2.43	3.09	3.15	3.21	3.27	3.32	3.55	3.18	3.43
Regulation									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	2.43	3.10	3.16	3.22	3.28	3.40	3.63	3.19	3.51
Higher Capital Cost									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	2.43	3.10	3.16	3.22	3.28	3.40	3.63	3.19	3.51
2/3 Revamp									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.00	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	2.43	3.10	3.16	3.22	3.28	3.40	3.63	3.19	3.51

According to the applicant:

> *"In the Regulation case, the marginal annual pump price for ULSD is projected to range from 6.5 to 7.2 cents per gallon between 2007 and 2011. The peak differential is projected to occur in 2011, when oil refiners must produce 100 percent ULSD."*

The applicant inferred from the table that difference shown between the Reference (0.05% S) case and the Regulation case (ULSD – 0.0015% S) represents market price differences. In fact, it actually represents the price differential of regulating diesel sulfur compared to what the price would have been in the absence of regulation.

For example, the table indicates a price difference of 7.2 cents per gallon in 2011. This is one of the values mentioned in the quoted excerpt from the application. It would be meaningless to discuss price differences in 2011 between available grades when the table specifically presumes no 0.05% sulfur fuel will be available.

EPA mandated the new grade of diesel because of the contribution of SO_2 to the formation of fine particulate matter in the environment as well as the possibility of poisoning catalysts used to control pollution from diesel engines. It is not unreasonable to require use of the superior grade as BACT in new exclusively diesel-fired sources of air pollution.

In the original application, KEYS estimates that maximum annual SO_2 emissions are 48 TPY based on use of 13,567,000 gallons of fuel oil No. 2 (4,420 equivalent hours). This assumes all sulfur is converted to SO_2. KEYS also assumes SAM emissions of 15 TPY. If the SAM emission estimate is correct, then SO_2 emissions will be equal to approximately 36 TPY which is less than the significant emission rate for SO_2.

Even if the KEYS SO2 emission estimates are correct, projections provided by KEYS indicate fuel oil use sufficient to cause 48 TPY of SO_2. Emissions will not actually reach that level until 2017. The fuel use corresponding to 40 TPY (the significant emission rate for SO_2) is 11,200,000 gallons. This level will not be reached until 2015.

It is doubtful that KEYS will ever emit more than 40 TPY based on:

- Correction of double-counting of sulfur as SO_2 and SAM
- Projected fuel use through 2015;
- Typical delivered sulfur content of low sulfur fuel oil (actually less than 0.05);
- Ultimate availability of ultralow sulfur at little or no premium.

The Department's BACT analyses for SO_2 and SAM control at operation beyond 2,500 hours indicate use of ultralow sulfur diesel fuel. However, KEYS has requested practicably enforceable limits of 39.9 tons of SO_2 and 6.9 tons of SAM per year to avoid BACT determinations and are proposing the use of 0.05 % sulfur fuel oil by weight. The SO_2 limit of 39.9 TPY will provide assurance, even assuming a worst case scenario of an SO_2 oxidation rate of 15% conversion of SO_2 to SO_3, and an assumed 100% conversion of SO_3 to H_2SO_4, that SAM emissions will remain below the significant level of 7.0 TPY.

Note: The Department can allow subtraction of the portion of sulfur that becomes SAM from the SO_2 calculation for the purposes of PSD applicability. This is irrespective of whether or not such a consideration is allowed for the purpose of determining use of SO_2 allowances under the Acid Rain Program.

4.4 Particulate Matter (PM/PM_{10}) BACT Determination

PM/PM_{10} Formation and Control Options

PM and PM_{10} are emitted from combustion turbines due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Low sulfur distillate fuel oil will be the only fuel fired and is efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure.

Applicant's PM/PM_{10} Proposal

KEYS proposed a BACT emission limit of 25 lb/hr for PM and the same value for PM_{10}. The most recent determination (City of Tallahassee) by the Department for an LM6000 PC SPRINT while operating on fuel oil is 15 lb/hr for PM and the same value for PM_{10}. However, the compliance method is a visible emission standard of 10%.

Department's Draft PM/PM_{10} BACT Determinations

The following conditions are established as the draft BACT standards.

- The gas turbines shall fire distillate oil that contains no more than 0.05% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

5. NEW SOURCE PERFORMANCE STANDARDS

5.1 Combustion Turbines

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These requirements result in the following standards based on compressor inlet conditions of 59° F and 60% relative humidity:

- NO_X (oil) $\leq$ 106 ppmvd @ 15% O_2 (corrected for a heat rate of 10.20 kJ/watt-hr assuming no fuel bound nitrogen; and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

A more recent standard was proposed by EPA on February 18, 2004. The proposed standard, 40 CFR60, Subpart KKKK would require adherence to the following limits:

- NO_X (oil) $\leq$ 1.2 lb/megawatt-hour. This is approximately equal to 35 ppmvd @15% O_2.
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.05% by weight.

The Department considers the draft BACT standards more stringent than the existing or the proposed NSPS standards. The GE LM6000 PC SPRINT will not meet the proposed NO_X standard without additional control such as proposed by the Department. The Department will request that EPA make a determination regarding KKKK applicability to the present project during the public comment period.

6. AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

In the original application, the proposed project predicted increases in emissions of four pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, NO_X, SO_2, and SAM. In the revised application, the predicted increases in emissions of two pollutants are at levels in excess of PSD significant amounts: PM/PM_{10} and NO_X. The following analyses are based on the revised application. PM_{10} 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.

6.2 Climate

The annual average high temperature for Key West is 83 degrees with their highest reported temperature being 98 degrees in 1997. The annual average low is 73 degrees. According to the National Weather Service in Key West, there is no known record of frost, ice, sleet, or snow in Key West. Prevailing easterly tradewinds and sea breezes suppress the usual summertime heating. Humidity remains relatively high during the entire year.

The wind rose below depicts the winds at Key West from 1987–1990, which are predominately from the east.

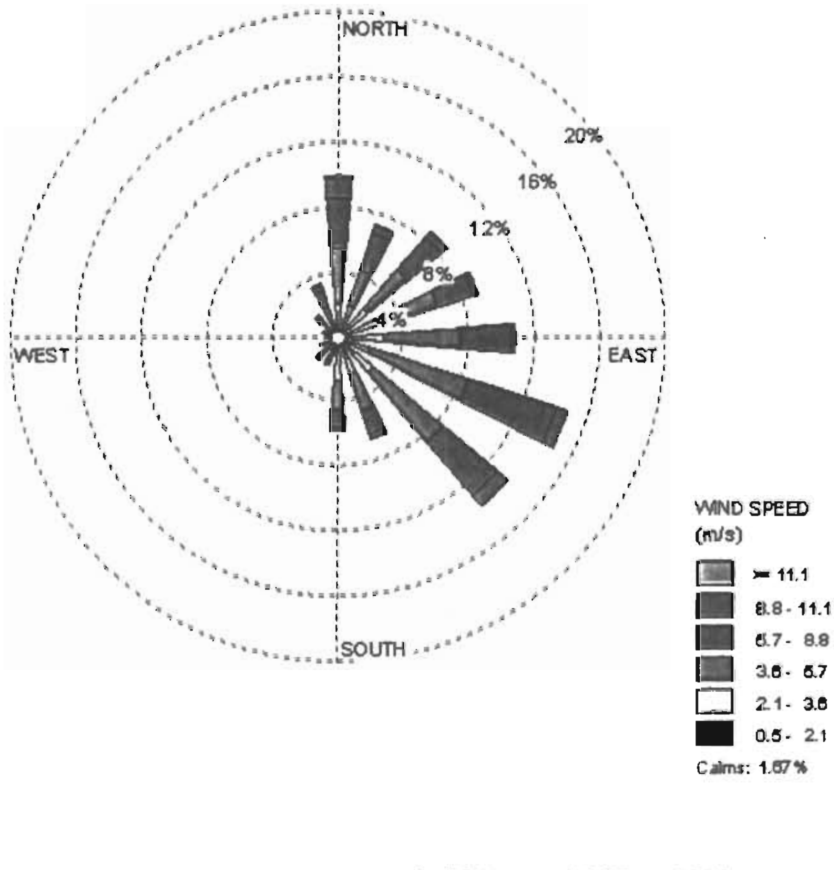


Figure 14 – Key West Wind Rose – 1987 to 1990

6.3 Major Stationary Sources in Monroe County

The current largest stationary sources of air pollution in Monroe County are listed below. The information is from annual operating reports submitted to the Department except as noted.

Table 11. Major Sources of NO_X in Monroe County (2003)

Owner	Site Name	Tons per year
KEYS Energy Services	Stock Island Power Plant (existing)	290**
KEYS Energy Services	***Stock Island Power Plant (proposed)***	***94.9***
City of Key West	Southernmost Waste to Energy Facility	83
KEYS Energy Services.	Cudjoe Key	63*
FL Keys Electric COOP Assoc.	FL Keys Electric COOP Assoc.	45

** Recently shut down*

***Potential to emit from Construction Permit*

Table 12. Major Sources of PM in Monroe County (2003)

Owner	Site Name	Tons per year
KEYS Energy Services	***Stock Island Power Plant (proposed)***	***31.3***
KEYS Energy Services	Stock Island Power Plant (existing)	37*
City of Key West	Southernmost Waste to Energy Facility	8
FL Keys Electric COOP Assoc.	FL Keys Electric COOP Assoc.	6

**Potential to emit from Construction Permit*

Emissions from the proposed project and the existing Stock Island Power Plant are the highest in the county. However, Monroe County does not have as many stationary sources as other Florida Counties and therefore, the conclusion that the emissions from Stock Island are high due to the information in the above tables cannot be made.

6.4 Air Quality and Monitoring in the Monroe County

Monroe County does not have an ambient air quality monitoring network. However, due to the location, climate, size and population of the county, it is assumed that air pollutant concentrations are less than other areas that have monitoring networks, such as Miami-Dade. The entire state of Florida is in attainment for all criteria pollutants.

6.5 Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for PM/PM_{10} and NO_X. 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 SILs for the PSD Class I Everglades National Park (ENP) and the PSD Class II Areas (everywhere except the ENP).

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

The applicant's initial PM/PM_{10}, and NO_X air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except ENP). These values are tabulated in the table below and are compared with existing National Ambient Air Quality Standards.

Table 13. Maximum Projected Air Quality Impacts from Stock Island Unit 4 for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.1	1	50	NO
	24-Hour	4.9	5	150	NO
NO_2	Annual	0.2	1	100	NO

Maximum predicted impacts from the project are much less than the respective AAQS 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 Everglades National Park (ENP) located about 90 km to the northeast 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}, and NO_X air quality impact analyses for this project indicated that maximum predicted impacts are less than the applicable SILs for the Class I area. Therefore no further detailed modeling efforts are required.

Table 14. Maximum Air Quality Impacts from the Stock Island Unit 4 Project for comparison to the PSD Class I SILs at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.0004	0.2	NO
	24-hour	0.02	0.3	NO
NO_2	Annual	0.0005	0.1	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 15. 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)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4.9	10	NO
NO_2	Annual	0.2	14	NO

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 Air Quality Analysis

PSD Class II Area: The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition.

The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. 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.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from Key West and West Palm Beach respectively. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

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 California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP. Meteorological MM4 and MM5 data used in this model was from 1990, 1992 and 1996.

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.

6.6 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Very low emissions are expected from gas turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, and NO_X as a result of the proposed project, including background concentrations, will be considerably less than the respective AAQS.

Since the project impacts are less than significant or considerably less than the AAQS, it is reasonable to assume the impacts on soils, vegetation, or wildlife (including the Endangered Key Deer) will be minimal or insignificant.

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 substantially lower than the significant impact levels (0.01 kg/ha/yr) determined by the National Park Service.

In addition, the National Park Service reviewed the proposal for CT Unit 4 at Stock Island and concluded that they "believe that there will not be any significant impacts on resources at the Everglades National Park."

Impact on Visibility:

The applicant submitted a visibility analysis for the Everglades National Park. The analysis included modeling from the CALPUFF model. The CALPUFF model predicted modeled impacts well below the 5% visibility impairment based on criteria from the NPS.

Growth-Related Impacts Due to the Proposed Project:

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth near the project.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, the population of Key West and Monroe County has grown by an average of 2% per decade since 1980. The population of Monroe County is currently about 80,000. In 1980, it was 63,000. In 1990, Stock Island had a population of about 3,600. The county depends on tourism economically. In 2000, 30% of the population worked in the tourism industry. With tourism being the main economic support for the Keys, the area is not a major industrial center. The main non-tourist related "industry" in the Keys is the military presence in the area.

Since 1977, there have been several projects at Stock Island including construction of two 8.8 MW diesel engines in 1990-91. One 23.5 MW combustion turbine was moved from Key West to Stock Island in 1995-96. Two 20 MW combustion turbines were installed in 1998. The Ralph Garcia Steam Unit was permanently retired in the 1980's. For reference, that unit still holds 2571 SO_2 allowances under the Federal Acid Rain program.

Southernmost Resource Recovery Facility surrendered its Title V Operation Permit in 2004 and permanently shut down.

Mobile source fuel quality has improved since the 1970's. The related reduction in transportation-related NO_X, SO_2 and VOC emissions probably offset increases due to traffic growth. The transportation-related decreases and the retirement of the Ralph Garcia Steam Plant and Southernmost Resource Recovery Facility provide a basis for concluding that there has not been a deterioration of air quality in the lower Keys since 1977. The proposed project is not likely to change that conclusion.

7.0 Preliminary Determination

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit.

Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Alvaro Linero, P.E., is the project engineer responsible for preparing the draft BACT determination and the permit as well as evaluating projecting the impacts on fuel supply. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

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Stock Island
Combustion Turbine No. 4

B&V Project 136839.0040
B&V File 32.0210
June 4, 2004

Al Linero
Florida Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Stock Island Combustion Turbine Unit 4 Project Class II and Class I Air Dispersion Modeling Protocols

The Florida Municipal Power Agency (FMPA) and Keys Energy Services (KEYS) are implementing the installation of a Nominal Net 47.6 MW General Electric (GE) LM6000 PC SPRINT combustion turbine operating solely on low-sulfur (0.05 percent) No. 2 distillate fuel oil in simply cycle mode (Project) at the KEYS Stock Island site in Key West, FL.

Since the proposed Project will be built at an existing major source, the major modification thresholds, or significant emission levels (SELs), will apply to the project. As such, the Project will be considered a PSD major modification source by the Florida Department of Environmental Protection (FDEP). It is anticipated that the proposed Project will be major for the following pollutants: NO_x, SO_2, and PM/PM_{10}, and sulfuric acid mist; thereby requiring Prevention of Significant Deterioration (PSD) review for those pollutants. As part of that review, an air dispersion modeling demonstration must be performed to ensure that the proposed Project will comply with the appropriate ambient air quality thresholds in the surrounding areas.

Prior to such demonstration, the attached air dispersion modeling protocols have been developed for your review in an effort to obtain concurrence with the proposed modeling methodologies. We would like to schedule a meeting with you to discuss the project. I will be contacting you in the near future to schedule a meeting. If you have any questions or comments, please feel free to contact me at 913-458-2126.

Regards,

BLACK & VEATCH

Bob Holmes

Bob Holmes
Air Quality Specialist

Enclosure

cc:

B. O'Neal – B&V
Jim Hay – FMPA
Susan Schumann – FMPA
Eddie Garcia – KEYS
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STOCK ISLAND UNIT 4 COMBUSTION TURBINE PROJECT

CLASS II AND CLASS I AIR DISPERSION MODELING PROTOCOLS

PREPARED BY
BLACK & VEATCH

MAY 2004

ATTACHMENT 1

STOCK ISLAND UNIT 4 COMBUSTION TURBINE PROJECT ISC MODELING PROTOCOL

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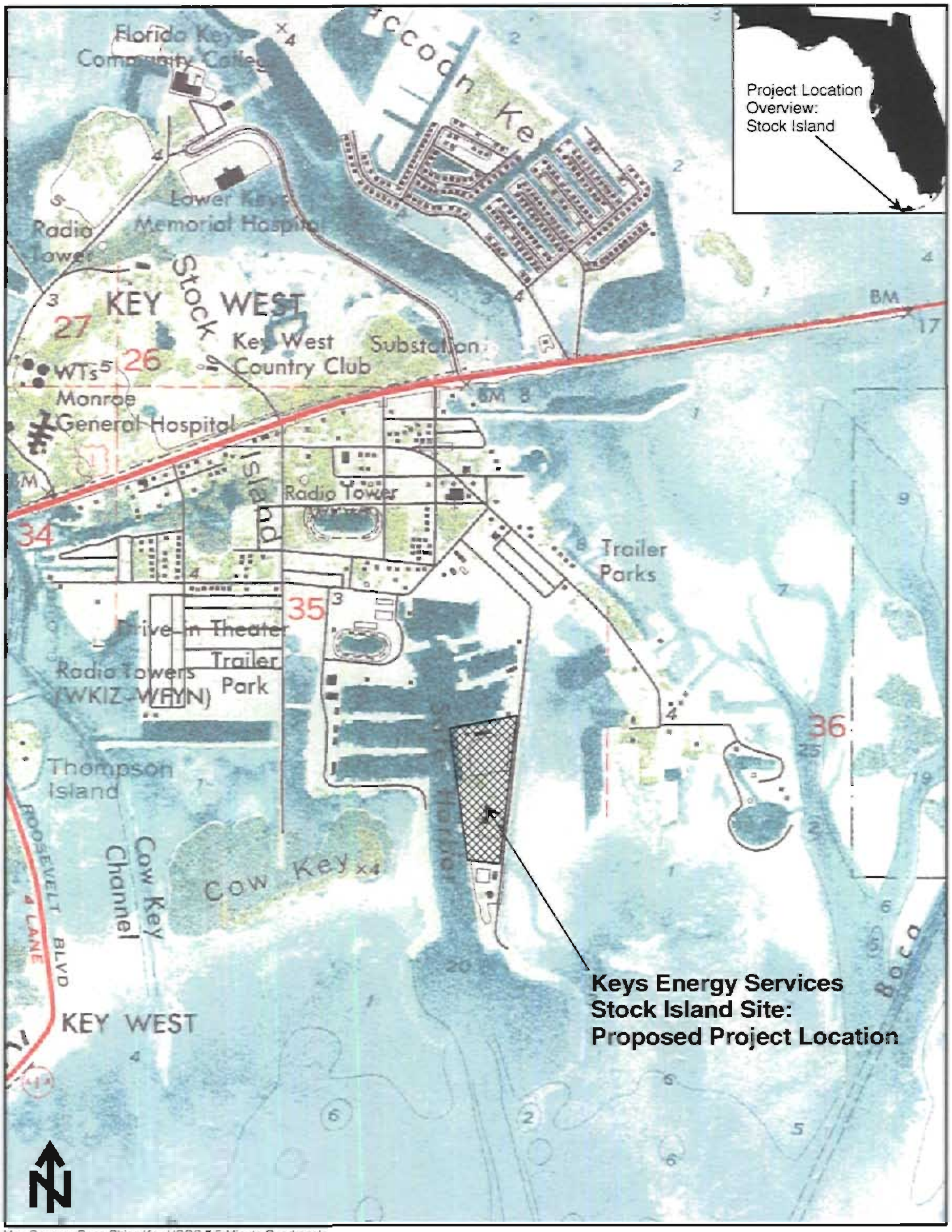
BLACK & VEATCH

MAY 2004

Air Quality Modeling Assumptions and Methodology

Modeling Scenario:	As a major modification to an existing PSD major source, the air quality impact analysis (AQIA) will be performed for Unit 4, a nominally rated 47.6 MW (net) simple cycle combustion turbine to be installed at the Keys Energy Services Stock Island site in Key West, Florida. The location of the proposed project is illustrated in the attached Figure.
Air Dispersion Model:	ISCST3 (Latest version)
Model Options:	EPA Default and Flat terrain.
GEP & Downwash:	EPA's BPIP program will be used to determine GEP stack height and direction specific building downwash parameters for the Unit 4 stack. Structures associated with the existing site, as well as the proposed additions will be included in the BPIP analysis.
Receptor Grids:	A 10 km nested rectangular receptor grid consisting of 100 m spacing out to 1 km, 250 m spacing from 1 km to 2.5 km, 500 m spacing from 2.5 km to 5 km, and 1,000 m spacing from 5 km to 10 km. Fenceline receptors will be placed at 100 m intervals, and a 100 m fine grid will be placed at maximum impact locations.
Dispersion Coefficients:	Rural: Based on visual inspection of a 7.5 minute USGS topographic map of the site using the Auer method.
Meteorological Data:	Refined level modeling sequential meteorological data will consist of surface data from the Key West International Airport and upper air data from Tampa, FL for the years 1987-1991. The files will be obtained from the Support Center for Regulatory Air Models website and processed with the USEPA meteorological processor PCRammet.
Pollutants to be Modeled:	The only pollutants that are currently expected to be modeled are PM_{10}, NO_x, and SO_2.
Source Modeling Parameters:	Worst-case hourly emission rates and operating parameters will be used for short-term modeling impacts. These data will be enveloped across 50, 75 and 100 percent load cases at ambient temperatures of 41, 78, and 95°F from representative combustion turbine performance and emissions data. Potential to emit calculations and operating

	parameters for annual modeling impacts will be based on annual average data.
Modeled impacts:	It is anticipated that the maximum model predicted pollutant impacts will be less than their respective PSD SILs. If the model predicted impacts exceed the SILs, additional agency consultation will be initiated regarding increment and cumulative air quality impact analyses.
Class I Analysis:	For analysis of the Everglades National Park Class I area, which lies beyond 50 km from the proposed modification, the CALPUFF model will be used. The CALPUFF modeling protocol is discussed in Attachment 2 of this submittal.
Toxics:	No toxic modeling analysis is required.



Map Source: Boca Chica Key USGS 7.5-Minute Quadrangle

Stock Island Combustion Turbine Unit 4
Proposed Project Location

ATTACHMENT 2

STOCK ISLAND UNIT 4 COMBUSTION TURBINE PROJECT CALPUFF MODELING PROTOCOL

PREPARED BY
BLACK & VEATCH

MAY 2004

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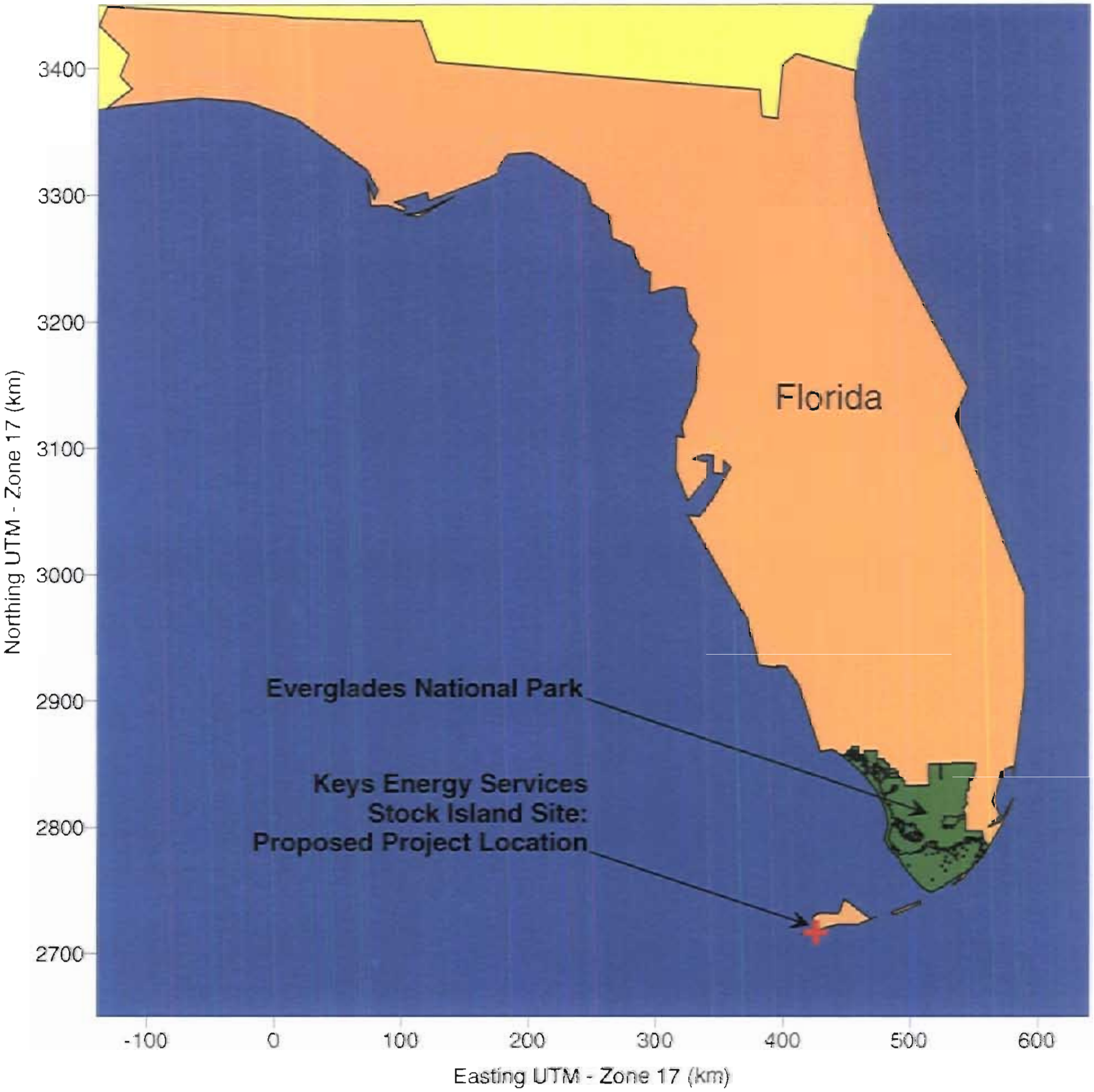
LIST OF FIGURES

1.0 Introduction

As part of the air impact evaluation for the proposed modification to the KEYS Stock Island site, analyses of the proposed project's effect on the Everglades National Park (ENP) will be performed. The ENP is a Prevention of Significant Deterioration (PSD) Class I area located in southern Florida approximately 90 km northeast of the proposed project site. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this protocol are regional haze and deposition. Additionally, Class I Significant Impact Levels (SILs) will be evaluated and compared to the recommended thresholds. Figure 1-1 presents the location of the proposed project site with respect to the ENP.

The methodology of the refined CALPUFF analysis will closely follow those procedures recommended in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report dated December 1998, the Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG) report dated December 2000 where appropriate for model option selections. This protocol includes a discussion of the meteorological and geophysical databases to be used in the analysis, the preparation of those databases for introduction into the modeling system, and the air modeling approach to assess impacts at ENP.



Proposed Project Location
with respect to
Everglades National Park

Figure 1-1

2.0 Model Selection and Inputs

2.1 Model Selection

The California Puff (CALPUFF, Version 5.711, Level 030625) air modeling system will be used to model the proposed project and assess the AQRVs at ENP. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces three-dimensional fields of wind and temperature and two-dimensional fields of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET will be input to CALPUFF to assess pollutant specific impacts.

2.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 2-1 will be used for the modeling analyses.

2.3 Building Wake Effects

The CALPUFF analysis will include the facility's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures will be processed with the Building Profile Input Program (BPIP), Version 95086, and included in the CALPUFF model input.

2.4 Receptor Locations

The CALPUFF analysis will use an array of discrete receptors for ENP, which were created and distributed by the NPS for standardized use in Class I analyses. Terrain throughout the ENP is included in the same NPS- provided receptor file.

Table 2-1 CALPUFF Model Settings	
Parameter	**Setting**
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional plume rise, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	<u>Regional Haze:</u> Highest predicted 24-hour change as processed by CALPOST. <u>Deposition:</u> Highest predicted annual total sulfur and nitrogen values in deposition units. <u>Class I SILs:</u> Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Monthly Ammonia: 0.5 ppb; Monthly background ozone will be based on a review of the available monitoring stations' values averaged for each month. Additionally, hourly background ozone values from several reporting stations may be assessed for inclusion into the CALPUFF modeling.

2.5 Meteorological Data Processing

The California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.53, Level 030709) will be used to develop the gridded parameter fields required for the refined AQRV modeling analyses. The following sections discuss the data to be used and processed in the CALMET model.

2.5.1 CALMET Settings

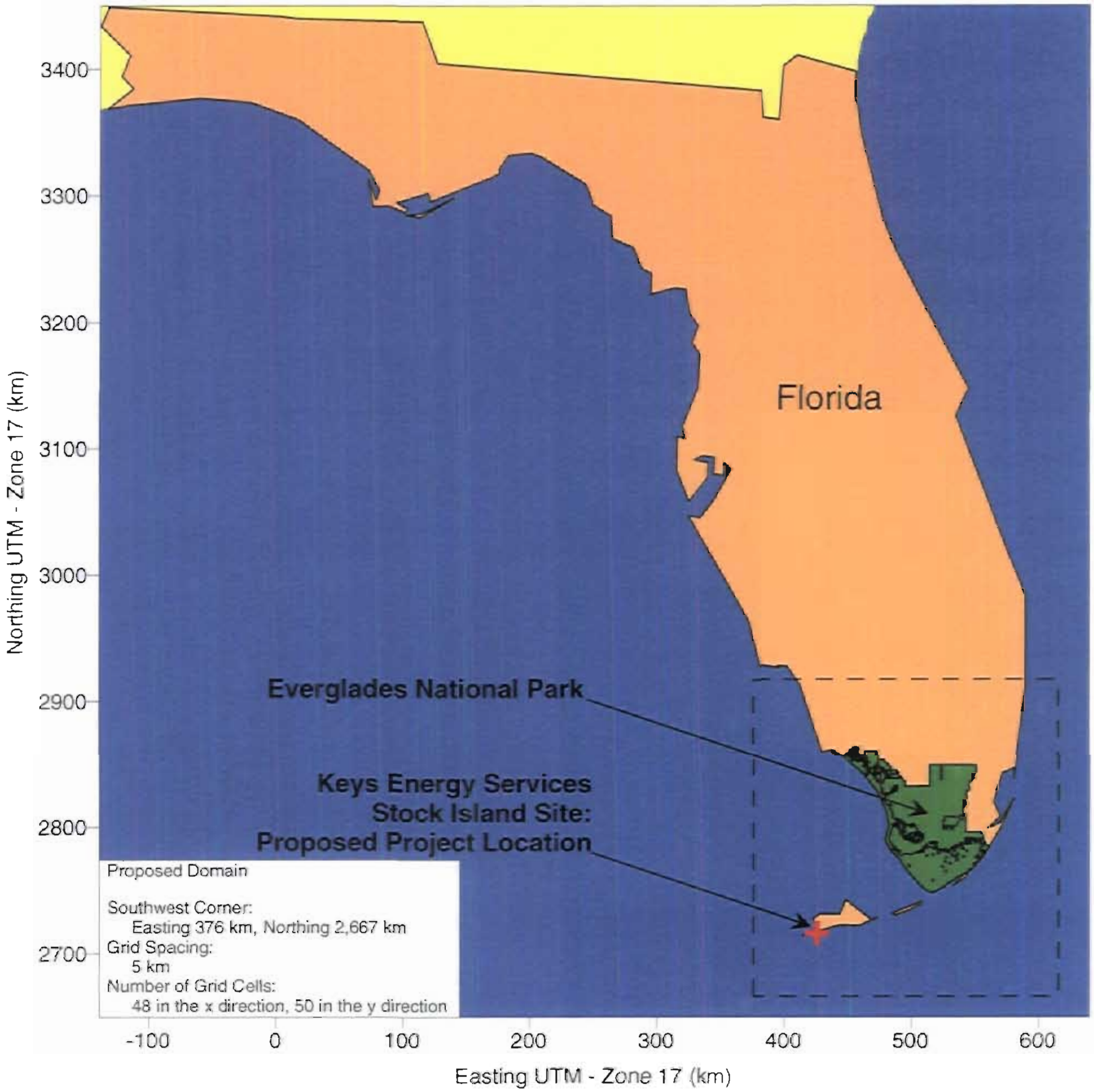
The CALMET settings, including horizontal and vertical grid coverage and resolution of prognostic mesoscale meteorological data, will be chosen to adequately characterize the area within the CALMET domain.

2.5.2 Modeling Domain

The size of the domain used for the modeling will be based on the distances needed to cover the area from the proposed project to the receptors at the ENP with at least a 50-km buffer zone in each direction. The modeling analysis will be performed in the UTM coordinate system. A rectangular modeling domain extending 240 km in the east-west (x) direction and 250 km in the north-south (y) direction will be used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 376 km Easting and 2,667 km Northing (based on UTM Zone 17, North American Datum (NAD) 1983 coordinates). The grid resolution for the domain will be 5 km. A grid spacing of 5 km yields 48 grid cells in the x-direction and 50 grid cells in the y-direction. Figure 2-1 illustrates the size and location of the modeling domain.

2.5.3 Mesoscale Model Data

Pennsylvania State University in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory have developed mesoscale meteorological data sets of prognostic wind fields, or "guess" fields, for the United States. The hourly meteorological variables used to create these data sets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and are used to populate the modeling domain with meteorological data. The analysis will use 1990 MM4, 1992 MM5, and 1996 MM5 mesoscale meteorological data sets to initialize the CALMET wind fields for each modeled year. The three years of MM data will be obtained from a NPS database provided to Black & Veatch. The extraction program accompanying the data will be used to obtain the



Proposed CALPUFF
Modeling Domain

Figure 2-1

appropriate MM data points to cover the modeling domain. The 1990 MM4 and 1992 MM5 data have a horizontal spacing, or resolution, of 80 km. The 1996 MM5 data has a resolution of 36 km. The meteorological observations contained with the MM data sets are assumed to be of sufficient density, both temporally and spatially, to make the need for discrete meteorological station observation unnecessary. Thus, CALMET will be run with the No Observations mode developed in the latest version available from the model developer, EarthTech.

2.5.4 Geophysical Data Processing

Terrain elevations for each grid cell of the modeling domain will be obtained from1-degree Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data will be extracted for the modeling domain grid using the CALMET preprocessor program TERREL. Land-use data, based on annual averaged values, will also be obtained from the USGS. Land-use values for the domain grid will be extracted with the preprocessor programs CTGCOMP and CTGPROC. Other parameters processed for the modeling domain include surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once preprocessed, all of the land-use parameters will be combined with the terrain information in a processor called MAKEGEO. This processor will produce one GEO.DAT file for input to CALMET.

2.6 Project Emissions

The maximum pound per hour emission rates at 100% load and the average annual temperature will be used for the pollutants modeled with CALPUFF. Those pollutants include NO_x, SO_2, and PM_{10}.

3.0 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system will be used to complete the Class I analyses on the ENP, including regional haze, deposition, and Class I SILs.

3.1 Regional Haze Analysis

A regional haze analysis will be performed for the ENP for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations.

3.1.1 Visibility

Visibility is an AQRV for the ENP. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the ENP lies beyond 50 km from the proposed project, the change in visibility is analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}(Mm^{-1}) = 3912 / vr(Mm^{-1})$$

Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level, a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient

A uniform incremental change in b_{extb} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

3.1.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of historical conditions at the ENP. The background visual range, or constituents thereof, for the ENP will be obtained from the Phase I FLAG Report, December 2000. The average relative humidity factor for each day will be computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the impact occurred. This factor, based on each relative humidity will be obtained by using Table 2.A-1 of Appendix 2.A of the Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) will then be used to determine the average relative humidity factor for that day (24-hour period). All of this is accomplished with the use of the CALPOST post-processor.

3.1.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analysis will follow the recommendations contained in the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts*, (EPA, 12/98) where appropriate. Table 3-1 summarizes the IWAQM Phase II recommendations. The methodology in Table 3-1 will be used to compute the results of the regional haze analysis. However, CALPOST now possesses the ability to

Table 3-1 Outline of IWAQM Refined Modeling Analyses Recommendations *	
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and source being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; NPS will provide the modeling receptors.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition 3. Define background values for ozone and ammonia for area
Processing	Use highest predicted 24-hr SO_4, PM_{10} and NO_3 values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction where appropriate. This can all now be accomplished with the use of Method 2 in the CALPOST post-processor.
* *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98).	

post-process the modeling results specific to the regional haze analysis through the selection of one of seven modeling options. The post-processing selection will be made to calculate regional haze based on the appropriate available data/resources. Specifically, regional haze will be calculated using Method 2, which consists of computing extinctions from speciated PM measurements using hourly relative humidity adjustments for observed and modeled sulfate and nitrates. Based on recent correspondence with staff of the NPS, the relative humidity will be capped at 95 percent. A supplementary analysis will be performed with the relative humidity capped at 98 percent for informational purposes only. Method 7, which eliminates hours during which visibility limiting weather events occur, may be explored as necessary. While this process occurs within CALPOST, a typical calculation methodology is illustrated below.

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24-hour SO_4, NO_3, and PM_{10} impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:
   $(NH_4)_2SO_4$ (μg/m3) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4
   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375
   Convert the NO_3 impact to NH_4NO_3 by the following formula:
   NH_4NO_3 (μg/m3) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3
   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29
3. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:
   $b_{exts} = 3 \times NH_4NO_3 \times f(RH) + 3 \times (NH_4)_2SO_4 \times f(RH) + 1 \times PM_{10}$
4. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLAG document with the following formula:
   b_{extb} = 3.912 / Visual range (km)
5. Compute the change in extinction coefficients:

in terms of deciviews:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

in terms of percent change of visibility:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

Based on the predicted SO_4, NO_3, and PM_{10} concentrations, the proposed project's emissions will be compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

3.2 Deposition Analyses

Deposition analyses will be performed for ENP for both total sulfur and total nitrogen. The analyses will follow those procedures and methodologies set forth in the IWAQM Phase II Report and the *Guide for Applying the EPA Class I Screening Methodology with the CALPUFF Modeling System* document, developed by Earth Tech, Inc. (the model developers) in September 2001. This document is a guide for using the POSTUTIL processor to perform deposition analyses. Specifically, deposition analyses will be performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 2.0 (including output of both dry and wet deposition).
2. Use POSTUTIL to combine the wet and dry flux output files from CALPUFF and scale the contributions of SO_2, SO_4, NO_x, NO_3, and HNO_3 such that total (i.e., wet and dry) nitrogen and total sulfur flux are contained in the same file. The POSTUTIL file is set up such that SO_2 and SO_4 contribute sulfur mass and SO_4, NO_x, HNO_3, and NO_3 contribute to the nitrogen mass.
3. Apply the appropriate scaling factors found in IWAQM Phase II Report (Section 3.3 Deposition Calculations) to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results are in kg/ha/yr.

The model-predicted results will be compared to the 0.01 kg/ha/year Deposition Analysis Threshold (DAT) developed jointly by the NPS and the U.S. Fish and Wildlife Service (FWS).

3.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) onto to the ENP will be calculated for NO_x, SO_2, and PM_{10} criteria pollutants for each applicable averaging period. The results of this analysis will be compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values. Should the model predicted impacts onto the ENP exceed the Class I SILs, an appropriately derived inventory of PSD increment consuming sources will be developed through FDEP and modeled with the CALPUFF modeling system for comparison to the Class I Increment values.

BLACK & VEATCH

11401 Lamar Avenue
Overland Park, Kansas 66211 USA

Tel: (913) 458-2000

Black & Veatch Corporation

FMPA/KEYS
Stock Island Combustion Turbine Unit 4

B&V Project 136839
File No. 33.1000
October 27, 2004

Patty Adams,
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
2600 Blair Stone Road MS 5500
Tallahassee, FL 32399-2400
(850) 488-0114

Subject: Stock Island Power Plant Construction Permit Application – Additional Copies

Dear Ms. Adams:

On behalf of the Florida Municipal Power Agency (FMPA) and Keys Energy Services (KEYS), per your request, enclosed please find two additional copies of the air construction permit application for the Stock Island Power Plant on Stock Island in Monroe County, Florida. The original application was received by the Florida Department of Environmental Protection on October 20, 2004.

If you have any questions, please contact Edward Garcia of KEYS at (305) 295-1134 or Susan Schumann of FMPA at (407) 355-7767.

Sincerely,

Bob Holmes

Bob Holmes
Air Quality Scientist
BLACK & VEATCH

Enclosures

cc: Edward Garcia, KEYS, w/out enc.
Susan Schumann, FMPA, w/out enc.
Stanley Armbruster/file, B&V, w/out enc.

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

November 10, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33401-6100

Re: Request for Additional Information
Combustion Turbine Unit 4 – GE LM6000 SPRINT
File No. 0870003-007-AC (PSD-FL-348)

Dear Mr. Cassel:

The Department is in receipt of your PSD application. However, in order to continue processing the application, we will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

A nominal 48 megawatts simple cycle General Electric LM6000 SPRINT combustion turbine is proposed. Wet injection will be used to reduce nitrogen oxides (NO_X) emissions to 42 parts per million by volume dry at 15 percent oxygen (ppmvd @15% O_2). This is in contrast to some recent projects that incorporate a selective catalytic reduction (SCR) system to achieve 5 ppmvd @15% O_2.whether they are fired with oil, gas, or both. The project apparently does not require further carbon monoxide (CO), or volatile organic compounds (VOC) because the PSD rules are not triggered for those pollutants and a determination of best available control technology (BACT) is not required.

The possibility of achieving NO_X values in the range of 15 to 25 ppmvd by using GE Dry Low Emissions (DLE) Technology is apparently not possible because DLE operates only on gas-fired LM6000 SPRINT. According to Keys Energy Services (KEYS), all options to provide gaseous fuels are infeasible (at least at this time) due to expensive infrastructure requirements that are presently not available. This review therefore concentrates on the fuel oil firing scenario and the possibilities of an SCR system to achieve BACT or to avoid PSD altogether.

Following are the issues we have identified or information needed to process the application:

1. Please recalculate total SCR capital and operating costs to account for a reduction from 154 tons per year (TPY) to 39 TPY of NO_X. This equates to a reduction from 42 ppmvd to roughly 11 ppmvd long-term average and not 5 ppmvd. At this level of control (~ 75%) the project would avoid PSD and a BACT determination.
2. Provide the details of the estimate of $1,894,000 by Deltak LLC that KEYS used as the basis for the SCR system and catalytic reactor housing (Page 4-18). Insure that this quote does not include a CO catalyst system or some of the other add-ons included by KEYS in estimating a total capital cost of $4,207,000. The KEYS estimate appears very high for SCR technology.

3. For reference, the City of Tallahassee estimated Total Direct and Indirect Capital costs at $1,676,180 for an SCR system to meet 5 ppmvd assuming 4,000 hours of fuel oil firing and 1,600 hours of natural gas firing. Please obtain information from the City of Tallahassee (available as public records). Compare and contrast the estimates with those provided by KEYS.

4. We recommend that KEYS obtain bids from other potential providers. We plan to obtain quotes if they are not supplied by KEYS.

5. FP&L proposes use of ultralow sulfur (ULS) fuel oil at Turkey Point. By the time the KEYS project starts up, or soon thereafter, this fuel will become the "market" for No. 2 fuel oil. This could reduce any conceivable concerns regarding formation of ammonium sulfate compounds by possible SCR system and, at the same time, meet BACT for SO_2 or even avoid PSD. Advise the names of suppliers contacted by KEYS to determine availability of ULS fuel oil and any problems associated with minor contamination by small amounts of the 0.05% sulfur fuel oil.

We have not yet received comments from EPA Region 4 or the National Park Service. We will promptly forward any comments they send us.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1), F.A.C., "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department ... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions, please call Cindy Mulkey at 850/921-8968.

Sincerely,

A. A. Linero, Administrator
South Air Permitting Section

Cc: Ron Blackburn, DEP
Edward Garcia, Keys Energy Services
Stanley Armbruster, P.E., Black & Veatch
Susan Schumann, FMPA
Jim Little, EPA Region 4
John Bunyak, National Park Service

FMPA / KEYS Stock Island Combustion Turbine #4
Meeting with FDEP

Monday, December 6, 2004 10:00am
At
Stock Island Power Plant

Agenda

I. Overview of Stock Island Combustion Turbine #4 Project

II. BACT for NO_X Control

III. R.A.I. Discussion

IV. Other Discussion

V. Site Tour

FMPA / KEYS Stock Island Combustion Turbine Unit 4

Air Construction Permit Application Meeting

December 6, 2004

Background

- 48MW GE LM6000 PC SPRINT to be constructed at Stock Island
- Proposed permitting operation for 13.576 million gallons per year fuel oil use, which is equivalent to 4422 full load hours per year - allows for operating flexibility
- The Stock Island Combustion Turbine Unit 4 Project is a PSD Major Modification, subject to PSD Review, requiring BACT analysis for NO_X, PM, PM_{10}, SO_2, and SAM
- Submittal of Air Construction Permit Application on October 20, 2004

ISCST3 Model Class II Impacts

Predicted Class II Impacts (100% Load)

Pollutant – Averaging Period	Modeled Impact (ug/m^3)	SIL (ug/m^3)	De Minimus Monitoring Levels (ug/m^3)
NO_X – Annual	0.16	1	14
PM/PM_{10} - 24 hour	1.45	5	10
SO_2 - 24 hour	1.37	5	13

Class I SIL Modeling Results

Predicted Impacts (1996 Worse Case)

Pollutant – Averaging Period	Modeled Impact (ug/m^3)	SIL (ug/m^3)
NO_X – Annual	0.0005	0.10
PM_{10} – Annual	0.0004	0.16
PM_{10} – 24 hour	0.024	0.32
SO_2 – Annual	0.0004	0.08
SO_2 – 24 hour	0.017	0.20
SO_2 – 3 hour	0.050	1.0

Proposed BACT Determinations

(Attachment 4, Page 1-1)

- NO_X emissions -- water injection and good combustion controls to achieve 42 ppmvd at 15 percent O_2
- PM/PM_{10}, SO_2, and H_2SO_4 emissions -- good combustion controls and low sulfur fuel oil (<0.05%)
- CO and VOC emissions -- annual emissions below PSD major source modification thresholds; BACT analysis not required

Selective Catalytic Reduction (SCR)

- SCR Not proposed as BACT for NO_x control for this unit due to the following:
  - SCR not cost effective at $12,191 per ton removed (slides 7-8)
    - (Attachment 4, Pages 4-17 through 4-24)
  - Unique aspects of Stock Island project (slide 9)
    - (Attachment 4, Pages 2-1 through 2-10)
  - SCR installation on this application has questionable reliability (slides 10-13)
    - (Attachment 4, Pages 4-5 through 4-13)

Factors affecting cost-effectiveness of SCR on Stock Island Unit 4

- Custom design for heavy marine environment
- Hurricane wind considerations
- Fuel oil only
- Limited vendor guarantees
- Limited space on Stock Island site
- Premium cost for labor; security concerns
- Access to site for equipment deliveries

Unique Aspects of Stock Island Project

- Single limited capacity transmission line
  (susceptible to storm-related outages)
- Frequent start-ups on fuel oil
- Limited road access to island
- Marine environment
- High cost impacts of a loss of power
- Unavailability of replacement power
- Limited access to fuel supplies
- Growing energy demand

Factors affecting reliability of SCR on Stock Island Unit 4

- SCR has not been demonstrated to be reliable on combustion turbines with high hours on oil
- BACT / LAER and Technology Review indicate water injection is primary form of NOx control when firing oil; only 4 oil-fired simple cycle combustion turbine generating units include use of SCR
  - (Attachment 4, Page 4-1; Appendix A)
    - Two additional simple cycle oil fired units identified on Long Island (Greenport and FPLE)
      - Unresolved SCR issues at Greenport

Factors affecting reliability of SCR on Stock Island Unit 4 (cont.)

- Limited operating history of SCR during fuel oil firing
  - (Attachment 4, Pages 4-8 to 4-9)
    - EPRI Fuel Oil Pilot Test; Shoreham; Puget Sound; PREPA Cambalache; Greenport Ls Long Island 750 hrs
- Recent Permitting Actions
  - (Attachment 4, Pages 4-9 to 4-12)
    - PREPA San Juan; VIWAPA Units 22 and 23; Commonwealth Chesapeake; Tallahassee
- No vendor experience on similar projects, including a simple cycle combustion turbine firing on fuel oil only in a marine environment with daily starts and extended hours
  - (Attachment 4, Page 4-9, and information from vendor guarantees)

Factors affecting reliability of SCR on Stock Island Unit 4 (cont.)

- SCR Operational issues while firing fuel oil
  - (Attachment 4, Pages 4-5 to 4-8)
    - Fouling and sooting
      - Distillate constituents produce sooty residue
      - Ammonium bisulfate
    - Mechanical failures
      - Due to thermal stresses associated with frequent starts
    - Thermal degradation
      - High temp catalyst or Dilution air required
    - Poisoning
      - Trace elements more prevalent in oil than in gas reduce catalyst life
      - Sodium poisoning, exacerbated in marine environment

Factors affecting reliability of SCR on Stock Island Unit 4 (cont.)

- Boiler vs CT
  - Travel distance and components between burner and catalyst
    - Oil carryover to catalyst minimized in boiler
    - More uniform gas distribution in boiler
  - CT operates at higher temperatures
  - CT subject to more starts

Conclusions

- Concerns regarding technical, energy, environmental and economic impacts of SCR
  - (Attachment 4, pages 4-23 and 4-24)
    - Cost-effectiveness ($12,191 per ton of pollutant removed; $22,849 per ton for the first 5 years)
    - Social, environmental and economic impacts
    - Technical factors
- Water injection and good combustion practices are proposed as BACT for NOx emissions from Combustion Turbine Unit 4.

FDEP Request for Additional Information

KEYS Combustion Turbine Unit 4

1. Please recalculate total SCR capital and operating costs to account for a reduction from 154 tons per year (TPY) to 39 TPY of NO_X. This equates to a reduction from 42 ppmvd to roughly 11 ppmvd long-term average and not 5 ppmvd. At this level of control (~ 75%) the project would avoid PSD and a BACT determination.

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   GE — Ats

   Deltech — Express

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energy services

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Key West, FL 33041-6100
www.KeysEnergy.com

UTILITY BOARD OF THE CITY OF KEY WEST

January 14, 2005

RECEIVED

JAN 18 2005

BUREAU OF AIR REGULATION

Al Linero,
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
2600 Blair Stone Road MS 5500
Tallahassee, FL 32399-2400
(850) 921-9523

Subject: Stock Island Power Plant Construction Permit Application
Response to Request for Additional Information/Comments
File No. 0870003-007-AC (PSD-FL-348)

Dear Mr. Linero:

Keys Energy Services (KEYS) respectfully submits the enclosed responses to your November 10, 2004 Request for Additional Information regarding the FMPA/KEYS Stock Island Power Plant Air Construction Permit Application. This enclosure also includes information addressing issues raised in a November 12, 2004 email that you sent to Susan Schumann of FMPA. An additional enclosure is provided to address the comments of Kathleen Forney of the USEPA as forwarded to FMPA and Black & Veatch by Cindy Mulkey of the FDEP Bureau of Air Regulation in a December 15, 2004 email. As required by Rule 62-4.050(3), F.A.C. these responses are certified by a professional engineer.

As discussed in a conversation between Cindy Mulkey and Susan Schumann on January 13, 2005, KEYS requests a meeting with FDEP and USEPA to clarify any issues which may still be unresolved following your review of the enclosed information. The responses provide clear evidence that a BACT determination requiring SCR is unprecedented and not applicable in a situation as unusual and unique as Stock Island Combustion Turbine #4. Furthermore, the economic evaluation of SCR, based on information received from vendors and compliance with FDEP and EPA standards, shows that it is inappropriate to determine SCR as BACT in this instance, as it is clearly not cost-effective.

We look forward to working with your office and staff as this application continues to proceed through the review process. If you have any questions, please contact Edward Garcia of KEYS at (305) 295-1134 or Susan Schumann of FMPA at (407) 355-7767.

Sincerely,
Keys Energy Services

Dan Cassel

Dan Cassel
Director of Generation

FMPA/KEYS
Mr. Al Linero

January 14, 2005

Enclosures

cc: Kevin Fleming, FMPA
Susan Schumann, FMPA
Jody Finklea, FMPA
Edward Garcia, KEYS
Diane Tremor, RS&B
Angela Morrison, HGS
Stanley Armbruster, B&V
Kathleen Forney, USEPA Region 4
C. Mulkey
O. Nelson
R. Blackburn, SD
G. Worley, EPA
J. Bunyak, NPS

FMPA/KEYS

STOCK ISLAND COMBUSTION TURBINE UNIT 4

AIR CONSTRUCTION PERMIT APPLICATION

RESPONSES TO REQUEST FOR ADDITIONAL INFORMATION

ENGINEERING CERTIFICATION STATEMENT

I, the undersigned, hereby certify that:

The engineering features of Stock Island Combustion Turbine Unit 4 Project described in these responses to requests for additional information have been prepared, or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles; and,

To the best of my knowledge, the information submitted in the responses is true, accurate, and complete based on reasonable techniques, estimates, materials, and information gathered and evaluated by qualified personnel.

Stanley A. Armbruster

Name: Stanley A. Armbruster
Florida License No. 30562
Date: January 14, 2005

Black & Veatch
11401 Lamar
Overland Park, Kansas

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Stock Island Combustion Turbine Unit 4 Air Permit Application Responses to Florida Department of Environmental Protection Requests for Additional Information And Email Comments

General Comment: A comment in an email from Al Linero to Susan Schumann dated November 12, 2004 questioned whether KEYS actually pays sales tax. After reviewing the tax status for FMPA/KEYS it was decided that sales and property taxes will be removed from the analysis. Therefore, these tax costs are not included in the analyses that are included in the RAI issue responses.

RAI Issue 1: Please recalculate total SCR capital and operating costs to account for a reduction from 154 tons per year (TPY) to 39 TPY of NO_X. This equates to a reduction from 42 ppmvd to roughly 11 ppmvd long-term average and not 5 ppmvd. At this level of control (~ 75%) the project would avoid PSD and a BACT determination.

RAI Issue 1 Response: To install and operate a SCR system designed to achieve an 11 ppmvd NO_x emission rate is expected to result in a reduction in the total capital investment and the total annualized cost of approximately $100,000 and $47,000, respectively as compared to a SCR system designed to achieve a 5 ppmvd NOx emission rate. The cost effectiveness $/ton value associated with an SCR designed to achieve an 11 ppmvd NO_x emission rate is expected to be approximately 16 percent greater than the cost effectiveness of a system designed to achieve a 5 ppmvd NO_x emission rate. The decrease in cost effectiveness (an increase in the cost effectiveness $/ton value) is due to the lower number of tons removed when controlling NO_x to 11 ppmvd. Since SCR is not required by BACT, it is inappropriate to install SCR to avoid PSD for NO_x.

Note that the startup/shutdown emissions for Combustion Turbine Unit 4 are expected to have a minimal contribution to the total annual emissions from this unit. Startup/shutdown emissions are discussed in more detail in Additional Issue 1 Response, which is included in this document.

RAI Issue 2: Provide the details of the estimate of $1,894,000 by Deltak LLC that KEYS used as the basis for the SCR system and catalytic reactor housing (Page 4-18). Insure that this quote does not include a CO catalyst system or some of the other add-ons included by KEYS in estimating a total capital cost of $4,207,000. The KEYS estimate appears very high for SCR technology.

RAI Issue 2 Response: Attached is the email budgetary quote on which the application BACT analysis was based. Deltak later confirmed the email budgetary quote as detailed in the response to RAI Issue 4. The original $1,900,000 capital cost in the email budgetary quote was adjusted for site requirements. The Deltak original price of $1,900,000 was modified to reduce the catalyst volume to the appropriate year operating hours of 7,000 hrs (4,422 equivalent full load operating hours) while adding the cost to reduce the NO_x outlet system to 5 ppm. These price modifications resulted in an increase of $44,200 in the base system price, resulting in a modified base system price of $1,944,200.

The Deltak scope did not include ammonia storage or the initial charge of ammonia solution and therefore, these items were added to the capital cost. The Deltak price included a stack which was subsequently deleted, since a stack is required with or without a SCR. Tempering dilution air was added because the outlet CT exhaust temperature could exceed 850 F. Making all of the adjustments noted here resulted in the $1,894,000 shown as the SCR system cost in the application BACT analysis.

As indicated in the email below, the quotation does not include a CO catalyst, CEMS, field erection or any other item that would unintentionally increase the SCR system capital cost for the Stock Island BACT analysis. The only item that was included in the quotation was a stack cost, which was subsequently removed. KEYS/FMPA has since requested further information to support a response to RAI Issue #4 and results of that action are outlined in the RAI Issue #4 Response.

Following is how the budgetary pricing was adjusted to cover items not included in the proposal.

SCR Catalyst, Housing Etc. -	$1,944,200
Ammonia Storage Tank -	45,000
Initial Charge of Ammonia -	4,800
Stack	(200,000)
Dilution Air System	100,000
Total	$1,894,000

Please note that the below email budgetary quotation is considered confidential.

```
-----Original Message-----
From: Dave Logeais [mailto:DLOGEAIS@deltak.com]
Sent: Tuesday, August 03, 2004 2:05 PM
To: Huggins, Roosevelt
Cc: Scher, John @ Mech. Sales
Subject: LM 6000 SCR SYSTEM / DELTAK B23255
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Roosevelt:

Based on your inquiry we propose to furnish one (1) Simple Cycle SCR Catalyst System for use with one (1) LM 6000 combustion gas turbine for the budgetary selling price of $1,900,000 FOB point of manufacture. Estimated shipping weight is 530,000 lb. Delivery is approximately 30 weeks after receipt of an order.

Our scope of supply includes inlet expansion joint, transition ductwork, catalyst housing, outlet stack, SCR catalyst, ammonia/air dilution skid, walkways and ladders, and control system.

We have not included CEMS, motor starters, CO oxidation catalyst, field erection, or catalyst hoist.

Performance is as you requested with 78.6% NOx reduction from 42 to 9 ppmvd when the combustion turbine is firing fuel oil. Ammonia slip is 10 ppmvd. Gas side pressure drop is less than 12 inches water column. Catalyst warranty is for three years or 24,000 operating hours, whichever comes first. Replacement SCR catalyst cost is currently about $350,000.

Please contact me if you need additional information.

David R. Logeais
Sr. Product Manager
763-557-7471

RAI Issue 3: For reference, the City of Tallahassee estimated Total Direct and Indirect Capital costs at $1,676,180 for an SCR system to meet 5 ppmvd assuming 4,000 hours of fuel oil firing and 1,600 hours of natural gas firing. Please obtain information from the City of Tallahassee (available as public records). Compare and contrast the estimates with those provided by KEYS.

RAI Issue 3 Response: The following Table RAI3-1 shows the Stock Island Combustion Turbine Unit 4 BACT cost evaluation, and the City of Tallahassee BACT cost evaluation (based on the revised BACT tables submitted to FDEP by the City of Tallahassee in response to an FDEP email request). With respect to the Tallahassee application, the BACT economic evaluations in Tallahassee's original application and responses to requests for information are incorrect. There are two major flaws in the evaluation. The first flaw is that Tallahassee had a vendor quote for a SCR and CO catalyst. Tallahassee assumed a 60/40 split in the SCR/CO catalyst cost. The split is incorrect. Information submitted by Seminole based on vendor quotes in their application indicates that the CO catalyst should be approximately 6.5 percent of the combined cost. This would result in a cost for Tallahassee's SCR of approximately $2,120,000 as opposed to $1,489,631 stated by Tallahassee.

The second flaw is that Tallahassee's quote for the SCR and CO catalyst was for equipment only, but the application assumed it was an installed price. Making these adjustments as well as other appropriate adjustments relative to Stock Island Combustion Turbine Unit 4 results in a $/ton removed with an SCR of approximately $9,430. In addition, Tallahassee's actual catalyst guarantee is for 5 years with a 1,500 hour per year limit on oil firing for a total of 7,500 hours of oil firing. Thus Tallahassee's SCR supports the one year catalyst life proposed by the applicant. When done correctly, Tallahassee's BACT evaluation does not support SCR as BACT.

Table RAI3-1
NO_x Emission Control Alternative Capital Cost for an SCR System
Stock Island Combustion Turbine Unit 4 vs. City of Tallahassee Costs (Incorrect)

	Stock Island	Basis for the Stock Island Analysis	City of Tallahassee	Basis for the City of Tallahassee analysis
Direct Capital Cost				
SCR System	1,894,000	Estimated from Deltak Corporation.	1,489,631	Vendor Cost of $2,482,718 for SCR/OC; assume 60% SCR system based on previous quotes.
Catalyst Reactor Housing	Included			
Control/Instrumentation	135,000	Estimated; includes controls and monitoring equipment.	Included	Additional NOx Monitor and System
Ammonia (Injection/Dilution/ Storage)	Included		Included	$35 per 1,000 lb mass flow developed from vendor quotes Vatavauk, 1990
Purchased Equipment Costs (PEC)	**2,029,000**		**1,489,631**	
Sales Tax	0	0% of PEC	Included	6% of SCR Associated Equipment and Catalyst
Freight	203,000	10% of PEC	Included	5% of SCR Associated Equipment
Total Purchased Equipment Costs (TPEC)	**2,232,000**		**1,489,631**	**(TDCC)**
Direct Installation Costs				
Foundation and supports	179,000	8% of TPEC	Included	8% of TDCC and RCC
Handling & Erection	312,000	14% of TPEC	Included	14% of TDCC and RCC
Electrical	89,000	4% of TPEC	Included	4% of TDCC and RCC
Piping	45,000	2% of TPEC	Included	2% of TDCC and RCC
Insulation	22,000	1% of TPEC	Included	1% of TDCC and RCC
Painting	22,000	1% of TPEC	Included	1% of TDCC and RCC
Total (Balance of Plant)	669,000	30% of TPEC.	Included	
Total Direct Cost (DC)	**2,901,000**		**1,489,631**	
Indirect Capital Costs				
Contingency	580,000	20% of DC	0	3% of TDCC
Engineering and Supervision	290,000	10% of DC	0	10% of TDCC
Construction & Field Expense	145,000	5% of DC	0	5% of TDCC
Construction Fee	290,000	10% of DC	0	10% of TDCC
Start-up Assistance	58,000	2% of DC	0	2% of TDCC
Performance Test	29,000	1% of DC	0	1% of TDCC
PSM/RMP Plan	NA		50,000	
Total Indirect Capital Costs (IC)	**1,392,000**		**50,000**	(TInCC)
Installed Costs (DC + IC)	**4,293,000**		**1,539,631**	Sum of TCC and TInCC (TDICC)
Less SCR Catalyst Cost	-369,000	Catalyst is viewed as an O&M value.	**NA**	
Total Capital Investment, TCI	**$3,924,000**	TCI = DC + IC	**1,539,631**	

RAI Issue 4: We recommend that KEYS obtain bids from other potential providers. We plan to obtain quotes if they are not supplied by KEYS.

RAI Issue 4 Response: FMPA/KEYS went out for several additional budgetary bids from potential providers. Additional bids were received from Deltak, ATS Express, GE Energy, and Nooter Ericksen. Turner Environmental provided a bid for a natural gas fired system, but did not respond with an additional bid when asked to resubmit based on a fuel oil fired system. Turner Environmental is the supplier of a SCR at the Greenport facility (simple cycle oil fired combustion turbine on Long Island) which is replacing its catalyst after only 1,400 hours of operation on kerosene.

A bid tabulation has been prepared comparing the Total Purchased Equipment Cost (TPEC) for each of these additional bids and is shown in Table RAI4-1.

It should be noted that freight for ATS Express and Nooter Ericksen in the attached table is based on the quote from Deltak. Deltak and GE both reviewed the delivery issues of shipping large equipment to Key West and both indicated the need to barge ship the SCR. Deltak provided a freight cost breakdown, but GE did not. ATS and Nooter Eriksen both provided freight costs based on trucking the equipment to the site and both indicated they had added a standard freight charge without reviewing the issues of trucking large equipment down the lengthy Florida Keys highway. Thus, the ATS and Nooter Eriksen freight quotes are not considered realistic.

The additional bids ranged in TPEC cost from $2,195,000 to $2,740,000 with the average TPEC cost at $2,407,000. Tables RAI4-2 and RAI4-3 show the BACT analyses with the original cost information (without sales and property taxes) and with the average TPEC cost from the additional vendor bids. The results from this analysis show that the cost analysis using the average of the additional vendor bids results in a SCR cost effectiveness of $11,900/ton of NO_x removed, which is still too high to be considered BACT. The analysis, if conducted using a three year catalyst life, gives a cost effectiveness of $8,960/ton of NO_x removed which also is too high to be considered BACT.

Attached are copies of the bid pricing received from the four vendors.

Table RAI4-1
NO_x Emission Control Alternative Capital Cost for an SCR System
Summary of Bids and TPEC Cost Analysis for Additional Vendor Bids

	Deltak	ATS Express	GE Energy	Nooter Ericksen	Average	Comments
SCR Catalyst, NH3 Skid, NH3 Injection & Dilution System, and Dilution Air Cooling System	1,919,200	1,700,000	2,850,000	1,665,000		Vendor quotes
Catalyst Reactor Housing	Included	Included	Included	Included		
Ammonia Storage Tank	45,000	160,000	Included	45,000		Estimated or vendor quote
Initial Ammonia Charge	4,800	4,800	4,800	4,800		Estimated
Controls and Instrumentation	135,000	135,000	85,000	135,000		Estimated
Expansion Joint	Included?	Included?	Included?	50,000		Vendor quote
Stack	(210,000)	Not Included	(200,000)	Not Included		Vendor quote
Dilution Air System	100,000	110,000	Included	Not Required		Estimated or vendor quote
Purchased Equipment Cost (PEC)	1,994,000	2,110,000	2,740,000	1,900,000	2,186,000	
Freight	295,000	295,000	Included	295,000		Vendor quote
Total Purchased Equipment Cost (TPEC)	2,289,000	2,405,000	2,740,000	2,195,000	2,407,000	

Table RAI4-2
NO_x Emission Control Alternative Capital Cost for an SCR System
Stock Island Combustion Turbine Unit 4
Application Basis Versus Average of Additional Bids

	Application Basis	Average of Additional Bids	Basis for the Stock Island Analysis
Direct Capital Cost			
SCR System	1,894,000	See TPEC	Estimated from Vendor quotes.
Catalyst Reactor Housing	Included		
Control/Instrumentation	135,000	See TPEC	Estimated or vendor quotes; includes controls and monitoring equipment.
Ammonia (Injection/Dilution/ Storage)	Included	Included	
Purchased Equipment Costs (PEC)	**2,029,000**	**See TPEC**	
Sales Tax	0	0	0% of PEC
Freight	203,000	See TPEC	10% of PEC
Total Purchased Equipment Costs (TPEC)	**2,232,000**	**2,407,000**	
Direct Installation Costs			
Foundation and supports	179,000	193,000	8% of TPEC
Handling & Erection	312,000	337,000	14% of TPEC
Electrical	89,000	96,000	4% of TPEC
Piping	45,000	48,000	2% of TPEC
Insulation	22,000	24,000	1% of TPEC
Painting	22,000	24,000	1% of TPEC
Total (Balance of Plant)	669,000	722,000	30% of TPEC.
Total Direct Cost (DC)	**2,901,000**	**3,129,000**	
Indirect Capital Costs			
Contingency	580,000	626,000	20% of DC
Engineering and Supervision	290,000	313,000	10% of DC
Construction & Field Expense	145,000	156,000	5% of DC
Construction Fee	290,000	313,000	10% of DC
Start-up Assistance	58,000	63,000	2% of DC
Performance Test	29,000	31,000	1% of DC
Total Indirect Capital Costs (IC)	**1,392,000**	**1,502,000**	
Installed Costs (DC + IC)	**4,293,000**	**4,631,000**	
Less SCR Catalyst Cost	-369,000	-317,000	Catalyst is viewed as an O&M value.
Total Capital Investment, TCI	**$3,924,000**	**4,314,000**	TCI = DC + IC

Table RAI4-3 NO_x Emission Control Annualized Cost for an SCR System Stock Island Combustion Turbine Unit 4 Application Basis Versus Average of Additional Bids			
	Application Basis	Average of Additional Bids	Basis for the Analysis
Direct Annual Cost			
Catalyst Replacement	446,000	383,000	Because the base catalyst cost was lower for one of the additional bids, the catalyst replacement cost for the average of the additional bids is lower than with the original application analysis.
Operation and Maintenance	67,000	70,000	This cost includes maintenance materials, which is a function of the TPEC.
Reagent Feed	63,000	63,000	Assumes 1.4 stoichiometric ratio.
Power Consumption	34,000	36,000	Includes injection blower and vaporization of ammonia for SCR.
Lost Power Generation			
Backpressure	117,000	112,000	Includes backpressure on CT.
Catalyst Replacement	241,000	241,000	Based on FMPA/KEYS energy cost and 7 day catalyst replacement.
Annual Distribution Check	55,000	55,000	Required for SCR.
Total Direct Annual Cost	**1,023,000**	**960,000**	
Indirect Annual Costs			
Overhead	40,000	42,000	60% of O&M Cost.
Administrative Charges	86,000	93,000	2% of Installed Costs.
Property Taxes	0	0	0%
Insurance	43,000	46,000	1% of Installed Costs.
Capital Recovery	431,000	474,000	CR = CRF*TCI
Total Indirect Annual Costs	**600,000**	**655,000**	
Total Annualized Cost	**1,623,000**	**1,615,000**	
Annual Emissions, tpy	18.3	18.3	Emissions calculated.
Emissions Reduction, tpy	135.8	135.8	Emissions calculated.
Total Cost Effectiveness, $/ton	**11,960**	**11,900**	Total Annualized Cost/Emissions Reduction.

RAI Issue 5: FP&L proposes use of ultralow sulfur (ULS) fuel oil at Turkey Point. By the time the KEYS project starts up, or soon thereafter, this fuel will become the "market" for No. 2 fuel oil. This could reduce any conceivable concerns regarding formation of ammonium sulfate compounds by possible SCR system. At the same time meet BACT for SO_2 or even avoid PSD. Advise the names of suppliers contacted by KEYS to determine availability of ULS fuel oil and any problems associated with minor contamination by small amounts of the 0.05% sulfur fuel oil.

RAI Issue 5 Response: As discussed on Page 6-1 of Attachment 4 of the Application, the fuel supplier contacted was Mr. Drew McIntosh of Coastal Fuels Marketing, the fuel supplier for the KEYS Stock Island Power Plant. Mr. McIntosh's telephone number is 954-355-4200. Mr. McIntosh indicated that it is possible that when the ULS fuel becomes mandated for Highway Diesel Fuel in June of 2006 that it may be available for delivery to Key West. He did not have an estimate of what the cost differential of the ULS fuel versus low sulfur fuel oil would be or what types of blends will be available when the ULS becomes more widely available.

FMPA/KEYS fully expects that at some time in the future, the natural fuel oil market will be such that ultra-low sulfur diesel (ULSD) will be used for Stock Island Combustion Turbine Unit 4 as well as the other Stock Island Units, but objects to it being made a permit condition for a number of reasons including the following.

From a BACT standpoint as presented in Pages 6-2 through 6-3 of Attachment 4 of the Air Construction Permit Application, based on 6.5 and 10.7 cents per gallon differential cost, the cost per ton of SO_2 removed is $19,006 and $31,287. Both amounts are clearly above the BACT cost per ton removed threshold.

The 10.7 cents per gallon differential cost results in a differential cost of $0.77/MBtu based on a heating value of 138,200 Btu/gal. Since the submittal of the Application, Black & Veatch has reviewed a confidential fuel forecast which projects a greater differential from 2006 which is the beginning of the phase in of ULSD through 2020 which is a full ten years past the date that the phase in is to be completed.

Because of the potential to be separated from the mainland for extended periods of time without the ability to obtain barge shipments of oil, FMPA/KEYS has a policy of maintaining a 14 day oil supply. Stock Island currently has two 0.5 million gallon fuel tanks and one 1.9 million gallon fuel tank. With the addition of Stock Island Combustion Turbine Unit 4, an additional 1.0 million gallon tank will be installed to maintain the 14 day supply. All tanks are piped together so that any unit can receive oil from any tank. If Stock Island Combustion Turbine Unit 4 were to require ULSD, it would have to be used for all units at Stock Island at a significant additional cost.

The applicant's consultant continues to research the causes of premature catalyst failure in combustion turbines burning fuel oil. While the sulfur in the fuel cannot be completely ruled out as a contributor, it has been determined that sulfur is not the leading cause of catalyst failure. As discussed in the Application, ammonium bisulfate is one mechanism for catalyst fouling, but it occurs when catalyst temperatures are low as a result of maldistribution of tempering air. When the catalyst reaches the proper temperature this ammonium bisulfate will evaporate from the catalyst.

Finally, the worst case model predicted Class II impacts are 5 percent, 37 percent, and 22 percent respectively of the SIL's for the Annual, 24 hour, and 3 hour periods as shown on Page 4-6 of the Application. Similarly, the worst case model predicted Class I impacts are 1 percent, 9 percent, and 6 percent respectively of the SIL's for the Annual, 24 hour, and 3 hour periods as shown on Page 5-14 of the Application. Thus SO_2 emissions are not an air quality impact issue.

As a matter of fact, law, and principle, the permit should not require ULSD as BACT nor should it have any unnecessary conditions or requirements for FMPA/KEYS to revisit the issue in the future. It should be noted that the City of Tallahassee, to which the EPA is comparing the FMPA/KEYS application, is not being required to use ULSD as BACT.

Additional issues from the November 12, 2004 email from Al Linero of FDEP to Susan Schumann of FMPA:

Additional Issue 1: After e-mailing the letter, I realized that it would be difficult to maintain emissions less than 39 tons per year to avoid PSD because of excess emissions during startups and shutdowns. You might want to estimate annual emissions to include startups/shutdowns whether the unit will be controlled by wet injection or wet injection plus SCR. It might take more control than 75% to reduce emissions to less than 39 TPY on years of high usage because I think your base emissions will actually be greater than the 154 ton estimate given in the application.

Additional Issue 1 Response: The estimated startup and shutdown emissions, supplied by GE, of an LM6000 were used to estimate the startup and shutdown emissions of Stock Island Combustion Turbine Unit 4. As indicated in the application, a limit on the annual quantity of fuel that can be fired in Combustion Turbine Unit 4 has been requested. To determine the incremental increase in NO_x emissions associated with startups/shutdowns during a year, the incremental difference in NO_x emissions per unit of fuel use was used as a basis. Based on an expected 200 startups/shutdowns during a year NO_x emissions from startups/shutdowns is estimated to be 1.23 tons per year. However, when taking into account the fuel burned during startups/shutdowns, which must be accounted for due to the proposed fuel limit, the net increase in NO_x emissions is only 0.4 tons per year. Therefore, when considering the effects of startups/shutdowns, the annual NO_x emissions would be expected to be 154.5 tons per year rather than the 154.1 tons per year listed in Table 2-2 of the permit application. This slight difference in estimated annual NO_x emissions should not affect the processing of the permit application. Because the SCR would not be effective in controlling NO_x emissions during startups/shutdowns, accounting for startup/shutdown emissions would actually result in a slight increase in the SCR dollar per ton of NO_x removed value determined as part of the BACT economic analysis.

The effect of startup/shutdown emissions under the scenario where NO_x from Combustion Turbine Unit 4 is controlled with a SCR system and the unit is limited to 39 tons per year NO_x emissions was also considered. The aforementioned rate of annual emissions due to startup/shutdowns would not preclude the use of a 39 ton per year emissions cap for Combustion Turbine Unit 4, as discussed in Issue 1 of the FDEP Request for Additional Information (RAI) dated November 10, 2004 and in Al Linero's email to Susan Schumann dated November 12, 2004. While the NO_x emissions from startups/shutdowns would use up part of a 39 ton per year limit, the difference could be made up by limiting hours of operation.

Additional Issue 2: I didn't dwell much on the cost estimates but you may want to consider: whether KEYS actually must pay sales tax; the actual rate at which KEYS borrows money (7% seems high); and the 20% contingency at $618,000 (also seems high).

Additional Issue 2 Response: After reviewing the tax situation for FMPA/KEYS it was decided that sales and property tax costs would be removed from the BACT analysis. The cost analyses included in the RAI responses reflect the removal of sales and property tax costs.

The 7 percent interest rate used to determine the capital recovery factor is consistent with that used by Seminole and the City of Tallahassee in their BACT cost analyses. Furthermore, the 7 percent interest rate is presented in the EPA's Air Pollution Cost Control Manual, January, 2002. The Manual describes it as a "social interest rate" The Manual goes on to say "When State, local Tribal and other government authorities assess pollution control costs, the seven percent interest rate employed in this Manual should produce estimations comparable to those established by the Agency when it performs its own evaluations." It is commonly acknowledged that while government entities and agencies such as FMPA/KEYS that can issue lower cost tax exempt bonds, the social interest rate associated with those bonds is much higher due to the avoidance of income tax. It should also be noted that BACT evaluation merely applies the capital recovery factor based on the 7 percent interest rate. The true carrying cost for a municipal agency such as FMPA/KEYS is much higher due to the additional costs of financing such as issuance fees, bond insurance, and required debt service reserve funds.

The cost evaluation is based on standard BACT cost factors which do not account for the unique features of the Stock Island site which increase the cost of installing a SCR. The unique features cost impacts have been incorporated by use of a higher contingency factor. These unique features include the following:

a. The type of labor needed for power plant erection is not available in Key West and travel of personnel from Miami will be required. This factor adds about 20 percent to the wage rate.
b. Higher cost of getting heavy construction equipment to the site from the mainland.
c. High cost of temporary housing of construction personnel in Key West.
d. The site has little lay down space. Much of the equipment will have to be stored off site at a lay down area to be rented by the construction contractor.
e. The foundation will have to have auger cast piles and the foundations must extend 3 to 4 feet above grade so the equipment is above the 100 yr flood and storm surges. Additional platforming, for employee access to the equipment, will also be required.
f. The project requires special Coast Guard security requirements due to its location. The requirements will impact construction and include special screening of all construction personnel and compliance with inspections and access restrictions.
g. Contractor will have to comply with the Coast Guard Maritime Security (MARSEC) requirement which will restrict access to the onsite lay down area which is near the fuel unloading dock when a fuel barge is at the site.

h. Working in a tight existing site which will increase costs and require added construction efforts such as moving underground lines. Also, space restrictions may require that the ammonia storage tank be built into the dike of the existing fuel oil spill containment which will require increasing the height of the containment berm.
i. The construction will be conducted during hurricane season and there is the possibility of disruption in schedule as well as damage during construction.

A BACT cost evaluation, as noted in the EPA cost manual, is +/- 30 percent. Based on the very nature of this estimate being +/- 30 percent accuracy, the utilization of a lower contingency value (such as three percent in the Tallahassee application) represents an estimating accuracy that technically cannot be achieved as part of this BACT process. A three percent accuracy level would represent detailed drawings, pipe routing, foundation design, and equipment procurements being developed and completed. None of these activities are completed as part of a BACT process. It is the professional opinion of the applicant's consultant, who has extensive experience in the installation of simple and combined cycle combustion turbine units and has certified the estimate for this BACT, that the value of 20 percent (which is allowed by OAQPS manual) is representative of the applicant's proposed project based on the above considerations and the level of detail developed to support the estimate. Also, the 20 percent contingency factor is consistent with the contingency factors used in the recent Seminole BACT analysis.

ATS Express LLC
9820 East 41st Street South, Suite 400
Tulsa, OK 74146-3616

Please note that the tempering air system fans also provide purge requirements, so deletion of these fans will require that the duct purge be accomplished with the CTG turning gear only, which can significantly increase startup times.

PRICING

Total Preliminary Price for One (1) System...$1,700,000.00
Ex Works, Tulsa, Oklahoma

Estimated Freight to Key West, Florida..$80,000.00
F.O.B. trucks / plant gate

Option for Four man-Weeks of Startup Assistance.....................................$32,000.00

Option for Ammonia Storage System..$160,000.00
(Scope as Noted in Options List)

Add for Tempering Air System...$110,000.00
(Scope as Noted in Options List)
(Typical Configuration shown on Plan View General Arrangement Drawing)

DELIVERY

Shipment of the gas path components can be accomplished twenty-eight (28) weeks after receipt of an order with full release to proceed with engineering and procurement, with the balance of mechanical components following within two (2) weeks. Catalysts would be delivered approximately thirty-six (36) weeks after order, which should allow time for the casing to be erected and the gas turbine to be run-in.

VALIDITY

Pricing and Delivery quoted herein are valid for acceptance through November 30th, 2004. After that date, pricing and delivery will need to be reconfirmed.

DELTAK

November 5, 2004

Florida Municipal Power Agency
8533 Commodity Circle
Orlando, FL 32819-9002

Attn: Mr. Kevin Fleming

Re: Florida Municipal Power Agency – Stock Island
Deltak Proposal No.: 9305

Dear Mr. Fleming:

We are proposing to furnish: One (1) Simple Cycle SCR Catalyst System as described in Deltak Proposal No. 9305 dated November 5, 2004 for the total budgetary selling price of $1,875,000.00 (U.S. Dollars).

(One Million Eight Hundred Seventy-Five Thousand)
(U.S. Dollars)

F.O.B. Point of Manufacture

Total estimated shipping weight: 531,700 lbs

Option Pricing:

Option 1 Freight to Jobsite ……………………………………TO FOLLOW
If this option is selected freight terms change to F.O.B. Trucks; Jobsite; Stock Island, Florida.

Option 2 Delete Outlet Stack……………………………………DEDUCT $210,000.00
If this option is selected the outlet stack will not be included in Deltak's scope of supply.

Option 3 Field Service ……………………………………*ADD $29,000.00*
Includes a Deltak Field Service Engineer at the jobsite for four (4) weeks. The work week consists of five (5) days Monday through Friday at eight (8) hours per day. All travel and living expenses are included. Two (2) round trips to the jobsite are included so the field service must be utilized in no less than two (2) week increments.

Terms:

This proposal is based on progress payments as follows:

- 10% Upon receipt of purchase order
- 15% Upon issuance of main submittal drawing package.
- 25% Upon receipt of major ductwork and stack material.
- 20% Upon shipment of major ductwork sections and stacks prorated to each individual unit.
- 15% Upon shipment of aqueous ammonia skids prorated to each individual unit.
- 15% Upon shipment of catalyst prorated to each individual unit.

Terms are net cash 30 days from date of invoice.
All payments in arrears are subject to a finance charge of 1% per month on outstanding balance.

Taxes:

The prices do not include any taxes. All applicable taxes, including, but not limited to, excise, use or sales taxes, GST, Value Added Tax, Customs Duties, Levies or any other taxes or assessments now or hereafter imposed or levied or increased by or under the authority of any federal, state or local law, rule or regulation concerning the equipment or the manufacture of sale thereof, shall be assumed and paid by the Purchaser, unless by applicable law such taxes must be collected or remitted by Deltak, in which event, the amount of such taxes shall be added to the price of the equipment.

Drawings:

Based on current engineering commitments, assembly drawings for your approval will be submitted in accordance with the schedule listed in Section 3.4 of the proposal.

Delivery:

Based on the availability of material and present shop conditions, the equipment described in this proposal will be delivered to the jobsite not later than 30 weeks after notice to proceed. Firm delivery commitments will be provided at the time of purchase.

Field Service:

Field service is included as an option. Additional service may be purchased at a per diem rate as described on the attached Field Service page.

Please do not hesitate to contact us if you have any questions.

Best regards,

David R. Logeais

David R. Logeais, P.E.
Sr. Product Manager
Specialty Boiler Systems

DRL/dks

Armbruster, Stanley A. (Stan)

From: Huggins, Roosevelt
Sent: Wednesday, November 10, 2004 10:21 PM
To: Worley, Judy L.; Armbruster, Stanley A. (Stan)
Cc: Rollins, Myron R.; Stock Island 136839
Subject: 33.0100 041110 STOCK ISLAND LM6000 / DELTAK #9305

FYI the file.

Roosevelt Huggins
-----Original Message-----
From: Dave Logeais [mailto:DLOGEAIS@deltak.com]
Sent: Wednesday, November 10, 2004 1:44 PM
To: 'Kevin.Fleming@fmpa.com'
Cc: Huggins, Roosevelt
Subject: STOCK ISLAND LM6000 / DELTAK #9305

Kevin:

You should have received our proposal on Monday. A price for Option 1, freight to the jobsite was not included. Normally we can ship the ductwork and stack modules as oversize and overweight permitted truck loads. However, because of weight and size limitations this is not possible to Stock Island. We will have to ship the duct and stack modules by ocean going barge. Getting freight estimates on this basis takes a little longer, which is why I didn't have it in time for the proposal. If shipping is included in our scope of supply we will barge the ducts and the base stack section to the dock. We will offload it from the barge and make the final transfer to the jobsite by truck.

The price add to ship the equipment to the jobsite is $295,000. If this add is accepted our freight terms will be FOB Trucks; Jobsite; Stock Island, Florida. This means we will get all of the equipment to the site. You are responsible for offloading it from the trucks at the jobsite.

Please contact me if you have additional questions.

David R. Logeais
Sr. Product Manager
763-557-7471

12 x 50 = 600

4.0 Commercial

4.1 Pricing

All pricing shall be considered budgetary at this time.

CIP, Jobsite (INCO 2000) price, w/o Tax and in US Dollars:

Plot Plan	Description	Qty	Budgetary Price $US
063	SCR System and auxiliaries as described	1	$ 2,850,000 USD
	Estimated cost of NOx catalyst replacement, Ex-Works, Catalyst Vendor's Facility. Pricing does not include transportation to site, or installation.	Lot	$ 301,000 USD

4.2 Delivery

Shipment of the gas path components can be accomplished thirty (30) weeks after receipt of an order with full release to proceed with engineering and procurement, with the balance of mechanical components following within two (2) weeks. Catalysts would be delivered approximately thirty-eight (38) weeks after order, which should allow time for the casing to be erected and the gas turbine to be run-in.

4.3 Validity

Proposal is budgetary and subject to adjustment based on review of Owner's specification, air permit and finalization of project specifics.

4.4 Warranty

The equipment supplied by GE will include a warranty that extends 12 months from operation or 18 months from equipment ready to ship, whichever occurs first.

4.5 Taxes / Duties

No sales or use taxes have been included in this quotation. The prices quoted exclude any Federal, State, or local taxes or fees that may be associated with the purchase of equipment and/or services.

No import/export duties have been included in this quotation. The prices quoted exclude any duties associated with the purchase or shipment of any equipment and/or services.

4.6 Terms and Conditions

This proposal is based upon standard GE Energy Terms and Conditions.

1. Commercial

1.1 Pricing

1.1.1 Base Price

Base price for one (1) Simple Cycle System behind a LM6000 combustion turbine as described in this proposal:		$ 1,665,000.

(One Million Six Hundred and Sixty Five Thousand US Dollars)

Estimated shipping weight (with optional stack & silencer): 540,000 lb

1.1.2 Options

Total Price for (1) Unit

1)	**ESTIMATED ADD** for freight F.O.B. to the jobsite plant gate for truck shipments of Base Scope (w/o stack) to Stock Island on Key West, Florida:		$ 65,000.
2)	**ADD** for 100 foot tall exhaust stack with EPA test ports and 360° access platform:		$ 260,000. Note 1 $ 25,000. +Freight
3)	**ADD** for stack acoustic silencer (with freight) to limit far field noise to 70 dBA at 250 feet and 5 feet above grade:		$ 35,000.
4)	**ADD** for erection consulting services and commissioning and operation training services on a per diem basis:		Article.1.2.7. Note 2
5)	**ADD** for payment and performance bond for 100% of the contract value. The bond will expire after the first year of warranty (not the year extra for repaired/replaced items):		$ 20,300.
6)	**ADD** for a Continuous Service Agreement to provide catalyst for a period of twenty (20) years assuming operating hour average if 7,000 hours per year over the twenty (20) year period:		$ *LATER.*
7)	**ADD** for hoist and monorail to load SCR catalyst:		$ 18,000.

8)	**ADD** for stairtower (if required by B&V or FMPA)		$ 60,000.
9)	**ADD** for 15,000 gallon reagent storage tank with transfer pumps and piping:		$ By Others.
10)	Cost of replacement SCR catalyst based on today's dollar (not including salvage or disposal costs of existing catalyst):		$ 160,000.
11)	Three (3) years operating life warranty on the SCR catalyst:		Included.
12)	Written functional description of operation to assist in programming (by others) of Owner's DCS and/or PLC:		Included.

Note 1: We quoted a 100-foot tall stack instead of a 60-foot tall stack. The cross-section of the SCR box is about 10' wide x 59' tall; a 60-foot tall stack will be too short. If a 60-foot tall stack is needed, we will be able to change the SCR cross-section to be more wide than tall, but this will take up more plot space and increase your erection costs.

Note 2: Ten (10) days of site technical assistance is included in our price. Additional time is available at the per diem rates in Article 1.2.7 of this proposal.

1.2 Terms and Delivery

1.2.1 Terms of Payment

% of Contract Price	Milestone
10%	Receipt of Purchase Order
10%	Submittal of Preliminary Footprint, Loads, and GA's
20%	Placement of Order for Catalyst System
20%	Commence Receipt of Large Structural Steel Column Material
20%	Delivery of First Shipment to Jobsite
10%	Shipment of All Casing and Stack
10%	Delivery of Catalyst
100%	

Stock Island Combustion Turbine Unit 4 Air Permit Application Responses to EPA's Preliminary Comments Date December 15, 2004

Issue 1: After looking it over, our first concern is the decision to not ever use ultra-low sulfur diesel (ULSD) fuel oil (FO). Although we understand there will be a transition period after it is on the market starting in January 2006, we feel that by the beginning of 2007, the proposed combustion turbine (CT) at Stock Island could be using FO with a sulfur content of 0.0015% (i.e., ULSD). By this time, prices and availability should have stabilized enough for KEYs to arrange for ULSD deliveries on a reliable basis. We suggest FDEP include a condition in the permit requiring Stock Island's newest CT to use ULSD by a certain date, with the idea that KEYS can revisit the BACT analysis if they feel it is still economically infeasible to use ULSD at that time. Furthermore, the lower sulfur content of the ULSD should help with the catalyst issues mentioned in the PSD application, when an SCR system is used to control NOx emissions.

Issue 1 Response: FMPA/KEYS fully expects that at some time in the future, the natural fuel oil market will be such that ultra-low sulfur diesel (ULSD) will be used for Stock Island Combustion Turbine Unit 4, but objects to it being made a permit condition for a number of reasons including the following.

From a BACT standpoint as presented in Pages 6-2 through 6-3 of Attachment 4 of the Air Construction Permit Application, based on 6.5 and 10.7 cents per gallon differential cost, the cost per ton of SO_2 removed is $19,006 and $31,287. Both amounts are clearly above the BACT cost per ton removed threshold.

The 10.7 cents per gallon differential cost results in a differential cost of $0.77/MBtu based on a heating value of 138,200 Btu/gal. Since the submittal of the Application in late October 2004, Black & Veatch has reviewed a confidential fuel forecast which projects a greater differential from 2006 which is the beginning of the phase in of ULSD through 2020 which is a full ten years past the date that the phase in is to be completed.

Because of the potential to be separated from the mainland for extended periods of time without the ability to obtain barge shipments of oil, FMPA/KEYS has a policy of maintaining a 14 day oil supply. Stock Island currently has two 0.5 million gallon fuel tanks and one 1.9 million gallon fuel tank. With the addition of Stock Island Combustion Turbine Unit 4, an additional 1.0 million gallon tank will be installed to maintain the 14 day supply. All tanks are piped together so that any unit can receive oil from any tank. If Stock Island Combustion Turbine Unit 4 were to require ULSD, it would have to be used for all units at Stock Island at a significant additional cost.

Black & Veatch continues to research the causes of premature catalyst failure in combustion turbines burning fuel oil. While the sulfur in the fuel cannot be completely ruled out as a contributor, it has been determined that sulfur is not the leading cause of catalyst failure. As discussed in the Application, ammonium bisulfate is one mechanism for catalyst fouling, but it occurs when catalyst temperatures are low as a result of maldistribution of tempering air. When the catalyst reaches the proper temperature this ammonium bisulfate will evaporate from the catalyst.

Finally, the worst case model predicted Class II impacts are 5 percent, 37 percent, and 22 percent respectively of the SIL's for the Annual, 24 hour, and 3 hour periods as shown on Page 4-6 of the Application. Similarly, the worst case model predicted Class I impacts are 1 percent, 9 percent, and 6 percent respectively of the SIL's for the Annual, 24 hour, and 3 hour periods as shown on Page 5-14 of the Application. Thus SO_2 emissions are not an air quality impact issue.

As a matter of fact, law, and principle, the permit should not require ULSD as BACT nor should it have any unnecessary conditions or requirements for FMPA/KEYS to revisit the issue in the future. It should be noted that the City of Tallahassee, to which the EPA is comparing the FMPA/KEYS application, is not being required to use ULSD as BACT.

Issue 2: Second, we disagree with some of the assumptions which were used in SCR cost analysis in the PSD application. The applicant calculated the cost effectiveness of installing SCR to control NOX emissions to be about $13,000 per ton of NOx removed. We have revised the cost analysis and estimated the cost effectiveness value to be about $6,500 per ton of NOX removed. Attached is a spreadsheet that contains our detailed comments on the SCR cost analysis and our revised calculations.

	City of Tallahassee		Stock Island - Proposed by KEYS		Stock Island - Revised by EPA	
	Dollars	% of DC	Dollars	% of DC	Dollars	% of DC
Total Direct Cost (DC)	$1,241,359		$3,092,000		$2,723,000	<- take out SCR cost here, not after indirect cost caluclations
Indirect Capital Cost						
Contingency	$37,241	3%	$618,400	20%	$81,690	3%
Engineering & Supervision	$124,136	10%	$309,200	10%	$272,300	10%
Construction & Field Exp.	$62,068	5%	$154,600	5%	$136,150	5%
Contractor/Construction Fee	$124,136	10%	$309,200	10%	$272,300	10%
Startup Assistance	$24,827	2%	$61,840	2%	$54,460	2%
Performance Test	$12,414	1%	$30,920	1%	$27,230	1%
PSM/RMP Plan	$50,000					
Total Indirect Cap. Cost	**$434,821**		**$1,484,160**		**$844,130**	
Installed Costs						
-SCR Catalyst Cost			-$369,000			
Total Capital Investment (TCI)	**$1,676,180**		**$4,207,160**		**$3,567,130**	
Direct Annual Costs	**Dollars**		**Dollars**	**Notes - BACT Cost Analysis**	**Dollars**	**Notes - assumption changes are in blue**
Operating Personnel	$18,720		$67,000	O&M	$67,000	
Supervision	$2,808					
Ammonia	$37,821		$63,000	Reagent	$47,250	75% of proposed, estimated from FDEP information
PSM/RMP Update	$15,000					
Inventory Cost	$2,844					
Catalyst Cost	$77,704		$478,000	1 year Cat. Life	$159,333	3 year cat life, vender information from FDEP
Contingency	$4,647		$55,000	Annual Distribution Check	$0	Distribution Check should be included in O&M
Total Direct Annual Costs	**$159,544**		**$663,000**		**$273,583**	
Energy Costs						
Electrical	$4,672		$34,000		$17,000	50% of electrical cost, more realistic estimate needed
MW loss and Heat Rate Penalty	$24,703		$358,000	<- Lost MW for Backpressure/	$35,800	<- Don't count Cat. Replacement downtime, Backpressure
Total Energy Costs	**$29,375**		**$392,000**	Catalyst Replacement Downtime	**$52,800**	should be based on replacement fuel cost (10% estimated)
Indirect Annual Costs						
Overhead	$35,609		$132,000	Overhead & Admin Charges	$111,543	60% O&M, 2% IC
Property Taxes	$16,762	1%	$126,000	2.75% TCI	$35,671	1% of TCI - estimate for increase in taxes solely b/c of SCR
Insurance	$16,762	1%	$46,000	1% of TCI	$35,671	1% of TCI
Annualized Total Direct Capital	$184,045	7%, 15 yr.	$461,946	7%, 15 yr.	$343,666	5%, 15 yr. - based on FDEP estimate of re-investment rate
Total Indirect Annual Costs	**$253,178**		**$765,946**		**$526,551**	
Total Annualized Costs	**$442,097**		**$1,820,946**		**$852,934**	
Total Cost Effectiveness ($/ton)	**$2,756**		**$13,409**		**$6,281**	
TPY NOx Removed	160.41		135.8		135.8	

Issue 2 Response: The following discusses each line item comment in the spreadsheet above which was attached to the email.

1. EPA Comment: Catalyst Cost should be taken out of Direct Cost not after development of Indirect Costs.

   Response: Removing the catalyst from the direct cost would not account for the indirect costs associated with the purchasing of the SCR catalyst. While the catalyst is calculated and applied as an annual consumable in this BACT determination, the indirect costs do apply because the indirect costs determined from the value of the catalyst such as contingency, engineering and supervision, construction and field expense, startup assistance and performance tests are costs that the applicant will experience due to addition of the catalyst.

   Including the catalyst in the direct cost for calculating indirect costs is typical in BACT determinations. Recent examples supporting this position are South Eastern Energy Corp in Alabama and Kissimmee Utility Authority Cane Island 3 in Florida.

2. EPA Comment: Contingency shall be 3 percent.

Response: A contingency of 20 percent is more representative for the Stock Island BACT economic determination than the recommended value of three percent of EPA for a number of reasons.

a. The type of labor needed for power plant erection is not available in Key West and travel of personnel from Miami will be required. This factor adds about 20 percent to the wage rate.
b. Higher cost of getting heavy construction equipment to the site from the mainland.
c. High cost of temporary housing of construction personnel in Key West.
d. The site has little lay down space. Much of the equipment will have to be stored off site at a lay down area to be rented by the EPC contractor.
e. The foundation will have to have auger cast piles and the foundations must extend 3 to 4 feet above grade so the equipment is above the 100 yr flood and storm surges. Additional platforming, for employee access to the equipment, will also be required
f. The project requires special Coast Guard security requirements due to its location. The requirements will impact construction and include special screening of all construction personnel and compliance with inspections and access restrictions.
g. Contractor will have to comply with the MARSEC requirement which will restrict access to the onsite lay down area which is near the fuel unloading dock when a fuel barge is at the site.
h. Working in a tight existing site which will increase costs and require added construction efforts such as moving underground lines. Also, space restrictions may require that the ammonia storage tank be built into the dike of the existing fuel oil spill containment which will require increasing the height of the containment berm.
i. The construction will be conducted during hurricane season and there is the possibility of disruption in schedule as well as damage during construction.

A BACT cost evaluation, as noted in the EPA cost manual, is +/- 30 percent. Based on the very nature of this estimate being +/- 30 percent accuracy, the utilization of a lower contingency value (such as three percent in the Tallahassee application) represents an estimating accuracy that technically cannot be achieved as part of this BACT process. A three percent accuracy level would represent detailed drawings, pipe routing, foundation design, and equipment procurements being developed and completed. None of these activities are completed as part of a BACT process. It is the professional opinion of Black & Veatch, who has extensive experience in the installation of simple and combined cycle combustion turbine units and has certified the estimate for this BACT, that the value of 20 percent (which is allowed by OAQPS manual) is representative of the applicant's proposed project based on the above considerations and the level of detail developed to support the estimate. Also, the 20 percent contingency factor is consistent with the contingency factors used in the August 2004 Seminole Florida BACT analysis.

3. EPA Comment: Reagent cost should be 75 percent of proposed.

   Response: The reagent cost submitted developed by the applicant's consultant was directly tied to the ammonia usage rate based upon a 1.4 NH3 to NO_X tons removed stoichiometric ration calculation. The calculation also factored in the unit capacity factor and the $700/ton aqueous ammonia cost estimated by an ammonia provider for the Stock Island plant site in Key West, Flroida. Therefore, reducing the ammonia reagent cost to 75 percent of the proposed value would be incorrect as the calculation is a direct consumption calculation.

4. EPA Comment: Catalyst Life shall be based on 3 year catalyst life in lieu of 1 year catalyst life.

   Response: As can be seen from the information below, the applicant has not identified any simple cycle oil fired SCR applications that in their **entire** operating life have operated successfully for more than a seventh of the hours required annually by this application. In fact, of the five simple cycle facilities identified with the capability to burn fuel oil and that have SCR's, two have experienced catalyst failures. Stock Island Combustion Turbine Unit 4 is expected to operate up to 7,000 hours per year at various loads which will be equivalent to the 4,422 hours of full load used in the BACT.

   Fuel oil firing in a simple cycle combustion turbine application is still a relative unknown in terms of experience for catalyst manufacturers. There are very few simple cycle SCR applications firing only fuel oil and no dual fuel applications with significant hours of operation on fuel oil. The following summarizes the operating experience of simple cycle oil fired combustion turbines with SCR as noted in the BACT contained in the PSD application:

   - EPRI Fuel Oil Pilot Test – Pilot test on an oil fired LM2500 in 1997 with the conclusion that simple cycle SCR oil fired applications were not a feasible technology.
   - PREPA Cambalache Power Plant – Installed in 1997 with catalyst failure after approximately 1,000 hours of operation and eventual permit modification to remove the requirement for SCR.
   - Puget Sound Energy Fredonia – Two units which began operation in 2001 and are permitted for oil and natural gas firing, but only have a couple hundred hours of operation on oil firing.
   - Shoreham Electric Generating Station – Two units installed in 2002 burning Jet Fuel A with less than 900 hours of operation through the 3rd quarter of 2004.

In addition, the applicant recently has identified two additional fuel oil fired simple cycle combustion turbine generator units with SCR on Long Island, NY. Relevant information on these units is noted below:

- Greenport – One Pratt & Whitney FT8 TwinPac unit with Turner Environmental SCR that started operation during the summer of 2003. The unit burns kerosene and has approximately 1,400 hours of operation. At 1,000 hours of operation, the SCR could not meet emissions and the unit is presently restricted to approximately 80 percent load, even though the SCR had a five year catalyst guarantee. For the Stock Island Combustion Turbine Unit 4, this would mean a load restriction in less than two months of service. Discussions with Turner Environmental indicated they have not identified the exact cause of the failure, but they are replacing the catalyst.
- Jamaica Bay – One Pratt & Whitney FT8 TwinPac unit with SCR that started operation in the summer of 2003. The unit is dual fuel, but initial operation has been on fuel oil with natural gas supply presently being installed. The owner will not discuss the operation of the unit, thus further information is not available. It is believed that the hours of operation to date would be similar to the Greenport facility.

The experience of oil fired boilers has been noted as proof that SCR will work on oil fired simple cycle combustion turbines. But, it should be noted that there are significant differences between oil fired boilers and oil fired simple cycle combustion turbines as noted below:

- Simple cycle combustion turbines, and in particular the Stock Island Combustion Turbine Unit 4, are subject to more starts than oil fired boilers which typically cycle load up and down, but do not start and stop.
- The combustion turbines' SCR operate at higher temperatures.
- The travel distance and path between the burners and the SCR catalyst are significantly different for oil fired boilers and oil fired simple cycle combustion turbines. The oil fired boiler has a much greater distance between the burners and the catalyst, a vertical gas path above the burners prior to turning horizontal, and tubes and structures in the gas path that result in more uniform gas distribution to the SCR as compared to a simple cycle combustion turbine.

While any one of these differences may not seem significant, the cumulative impact causes the applicant and Black & Veatch to question the applicability of oil fired boiler SCR experience to simple cycle combustion turbine SCR expected catalyst life. It should be noted that the Cambalache and Greenport catalyst failures have occurred over 20 years after installation of some of the first oil fired boiler SCR's.

The catalyst life guarantees offered by catalyst vendors are prorated guarantees, which require a portion of or all of the replacement costs to be borne by the applicant, as well as other associated costs such as lack of availability of the generating unit. Furthermore, the warranty conditions of the catalyst vendors have provisions which in many instances will cause the warranty to be voided. An example of one of these provisions is that oil on the catalyst will void the warranty. With the daily starts required by this application, it is certain that a false start will occur at some point during the three year warranty period resulting in oil getting on the catalyst. It should also be noted that in response to FMPA/KEYS request for budgetary quotes for the Stock Island Combustion Turbine Unit 4 (requested in response to a FDEP RAI), Turner Environmental (SCR supplier on Greenport) provided only a natural gas fired SCR quote and did not re-quote when requested to provide an oil fired based SCR. In addition, Tallahassee's actual catalyst guarantee is for five years with a 1,500 hour per year limit on oil firing for a total of 7,500 hours of oil firing.

In summary, the use of a one year catalyst replacement period is over seven times longer than any identified successful experience. Black & Veatch and the professional engineer certifying these responses state that the appropriate catalyst life in the BACT evaluation for the Stock Island Combustion Turbine Unit 4 is one year and that a three year life is inappropriate based on the experience identified above and in the PSD application.

5. EPA Comment: Distribution Check should be part of O&M.

   Response: The distribution check is a separate cost that is a necessary preventive maintenance function required to be procured by the Owner to maintain the catalyst guaranteed life. The distribution checks are performed by the catalyst vendor or a consultant. The distribution check scope of work includes review and tuning of the ammonia grid settings, removal and analysis of catalyst test coupons by a lab, inspection of catalyst frame and distribution device, and evaluation of emission and formal test records on a regular basis. The other categories in the annual costs do not address this cost; therefore, the applicant's consultant provided it as a separate line item. The cost of the distribution check is typically included in BACT costs in other applications.

6. EPA Comment: Shall be 50 percent of electrical cost.

   Response: The additional loads for the SCR include the dilution air fans and the ammonia vaporization. The dilution air fans are 70 hp or 52.22 kW at 0.746 kW/hp. The ammonia vaporization is based on 83.816 tons/yr of ammonia for the full load equivalent of 4,422 hours at 2 kW/lb or 75.82 kW for a total kW load of 128.04 kW. The cost of the electrical energy is based on the 4,422 hours of equivalent full load operation times the energy cost of $0.05925/kWh or $34,000. The energy cost is based on FMPA/KEYS's wholesale rate. FMPA/KEYS's wholesale rate is an average for the whole system. It does not take into consideration the higher costs of generation in Key West.

7. EPA Comment: Don't count catalyst replacement downtime. Backpressure should be based on replacement fuel cost.

Response: Catalyst replacement is an inherent cost of the SCR system. While the catalyst is being removed, the CT can not generate electricity. The basis of this application is that the CT will operate up to 7,000 operating hours per year at various load scenarios. Therefore, catalyst replacement will place an undue burden on the applicants whether the catalyst life is a 1 year or 3 year basis. This burden should be calculated as an annual cost.

The cost was calculated based on a 7 day downtime for replacement at the FMPA/KEYS wholesale rate of $0.05925/kWh at the average capacity factor of the unit which is based on 4,422 full time equivalent hours per year. The annual cost for catalyst replacement downtime is $241,000.

The cost for lost power output due to backpressure is calculated as follows. The lost output due to backpressure is 465.60 kW. At 4,422 full time equivalent hours with outage time considerations and $0.5925/kWh, the cost is $117,000. FMPA/KEYS believes that the wholesale rate is the appropriate cost of power to use.

8. EPA Comment: Property Tax shall be decreased from 2.75 percent of TCI to 1 percent of TCI.

   Response: FMPA/KEYS does not have to pay property taxes and they will be deleted from this analysis.

9. EPA Comment: Interest Rate shall be 5 percent in lieu of 7 percent.

   Response: The 7 percent interest rate used to determine the capital recovery factor is consistent with that used by Seminole and the City of Tallahassee in their BACT cost analyses. Furthermore, the 7 percent interest rate is presented in the EPA's Air Pollution Cost Control Manual, January, 2002. The Manual describes it as a "social interest rate" The Manual goes on to say "When State, local Tribal and other government authorities assess pollution control costs, the seven percent interest rate employed in this Manual should produce estimations comparable to those established by the Agency when it performs its own evaluations." It is commonly acknowledged that while government entities and agencies such as FMPA/KEYS that can issue lower cost tax exempt bonds, the social interest rate associated with those bonds is much higher due to the avoidance of income tax. It should also be noted that BACT evaluation merely applies the capital recovery factor based on the 7 percent interest rate. The true carrying cost for a municipal agency such as FMPA/KEYS is much higher due to the additional costs of financing such as issuance fees, bond insurance, and required debt service reserve funds.

Issue 3: The applicant has proposed water injection (42 ppm) as BACT for control of NOx emissions from the simple cycle LM6000 CT. The applicant seems to have rejected SCR as BACT for the CT at Stock Island for several reasons, including their cost effectiveness calculations and the fact that SCR has seldom been required as BACT for NOX control from simple cycle CTs. However, as mentioned by the applicant, FDEP just recently permitted another simple cycle LM6000 CT (City of Tallahassee; PSD-FL-343), which will install SCR to control NOX emissions down to 5 ppm. Based on the revised cost analysis attached and discussions with FDEP, we believe that SCR represents BACT for NOx emissions at simple cycle CTs, even those that burn only FO.

Issue 3 Response: FMPA/KEYS firmly believes that BACT for NO_X should be 42 ppm with water injection based on the definition in Rule 62-210.200(37), F.A.C. which requires the "maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs." The economics clearly indicate that SCR is not required. Furthermore, there are many unique aspects relative to Stock Island Combustion Turbine Unit 4 that prevent BACT being SCR. These unique energy, environmental, and economic impacts are summarized in Section 2.1 of Attachment 4 of the application.

With respect to the Tallahassee application, the BACT economic evaluations in Tallahassee's original application and responses to requests for information are incorrect. There are two major flaws in the evaluations. The first flaw is that Tallahassee had a vendor quote for a SCR and CO catalyst. Tallahassee assumed a 60/40 split in the SCR/CO catalyst cost. The split is incorrect. Information submitted by Seminole based on vendor quotes in their application indicates that the CO catalyst should be approximately 6.5 percent of the combined cost. This would result in a cost for Tallahassee's SCR of approximately $2,120,000 as opposed to the $1,489,631 stated by Tallahassee. The second flaw is that Tallahassee's quote for the SCR and CO catalyst was for equipment only, but the application assumed it was an installed price. Making these adjustments as well as other appropriate adjustments relative to Stock Island Combustion Turbine Unit 4 results in a $/ton removed with an SCR of approximately $9,430. In addition, Tallahassee's actual catalyst guarantee is for five years with a 1,500 hour per year limit on oil firing for a total of 7,500 hours of oil firing. This is slightly more than one year of Stock Island Combustion Turbine Unit 4 operation. Thus, Tallahassee's SCR supports the one year catalyst life proposed by the applicant. When done correctly, Tallahassee's BACT evaluation does not support SCR as BACT.

Issue 4: Finally, we would like the applicant to consider the following options
1) accepting additional voluntary restrictions on hours of operation/total amount of fuel oil consumed or
2) installing SCR and controlling NOx emissions down to a level of about 10ppm which would allow the project to avoid PSD for NOx altogether, if so desired.

Issue 4 Response: FMPA/KEYS has already reduced the hours of operation/total amount of fuel consumed to the minimum projected to be required. This combustion turbine will meet FMPA/KEYS load in the Keys area that is above the capacity of transmission line to the mainland and will usually operate daily. It is not a peaking unit as are most simple cycle combustion turbine installations.

Since SCR is not required by BACT, it is inappropriate to install SCR to avoid PSD for NO_X.

FMPA / KEYS Stock Island Combustion Turbine Unit 4

Air Construction Permit Application Meeting
February 3, 2005

FMPA/KEYS concerns regarding SCR

- SCR is not appropriate as BACT for NO_x control for this unit TOOK OUT SALES & PROPERTY TAX
  - SCR not cost effective at $11,900 per ton removed
  - Unique aspects of Stock Island project
  - SCR installation on this application has questionable reliability DISAGREE
  - There is no air quality impact issue for NOx emissions

Unique Aspects of Stock Island Project contribute to difficulty in construction, operation and maintenance of CT4

DOWN TO 50% AND LOWER

- Single limited capacity transmission line
- Frequent start-ups on fuel oil
- Limited road access to island
- Marine environment
- High cost impacts of a loss of power
- Unavailability of replacement power
- Limited access to fuel supplies
- Growing energy demand

WANT TO RUN BY 2006 HURRICANE SEASON

Unique physical features on Stock Island significantly increase cost of SCR installation and operation

- Labor costs are higher. Skilled workers must travel from Miami and stay in high-cost temporary housing
- Transporting heavy equipment from mainland is difficult and expensive
- Site limitations will require off-site storage of equipment and customized engineering and construction.
- Fortified foundation and platforming will be required
- Stringent Coast Guard security requirements will impact site access, construction, and personnel screening

Vendor guarantees are not adequate to represent unique aspects of this project

- No vendor can provide previous experience with a similar project
- There is no vendor market for SCR operation on fuel-oil only CT's
- The quote provided by GE, which results in a cost-effectiveness of $12,548 per ton NOx removed, reflects the most thorough understanding of the uniqueness and costs involved in this project

Proposal of Three-year catalyst life is not acceptable

- Current FMPA/KEYS proposal includes annual operating hours that exceed any successful catalyst life of existing permitted oil-fired units by 4-5x
- Five units identified with operational history of SCR on fuel oil
  - 2 units have experienced early catalyst failure
  - 3 remaining units have not exceeded 900 total hours of operating history on any unit
- FMPA/KEYS propose one-year catalyst life

Summary of Operating Experience

Unit	Year Installed	Operating Experience
Cambalache	1997	Catalyst life of 1000 hours on diesel
Fredonia	2001	Dual fueled; only 200-300 hours of operation to date on diesel
Shoreham 1 & 2	2002	900 hours of operation to date on Jet A
Greenport	2003	Catalyst life of 1000 hours on kerosene
Jamaica Bay	2003	No information available

FMPA/KEYS concerns regarding ULSD

- ULSD is clearly not BACT
  - Cost per ton SO2 removed is between $19,000 and $31,000
- High additional costs to use ULSD in existing KEYS units
- Sulfur is not a leading cause of SCR catalyst failure on oil-fired operations
- No air quality impact issue for SO2 emissions

Summary

- Cost effectiveness and uniqueness of Stock Island site preclude the determination of SCR as BACT for NOx emissions.
- It is not appropriate to require ULSD fuel at Stock Island as a permit condition at this time.

keys energy services

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1001 James Street
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Key West, FL 33041-6100
www.KeysEnergy.com

UTILITY BOARD OF THE CITY OF KEY WEST

February 16, 2005

Al Linero,
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
2600 Blair Stone Road MS 5500
Tallahassee, FL 32399-2400
(850) 921-9523

Subject: Stock Island Power Plant Construction Permit Application
Response to Florida Department of Environmental Protection
Supplemental Request for Additional Information
File No. 0870003-007-AC (PSD-FL-348)

Dear Mr. Linero:

Keys Energy Services (KEYS) respectfully submits the enclosed responses to supplement the responses to the Request for Additional Information, which were previously submitted to FDEP by KEYS on January 18, 2005. These supplemental issues were raised as a result of the meeting between FDEP, USEPA (by conference call), KEYS, and Florida Municipal Power Agency (FMPA) on February 3, 2005. As required by Rule 62-4.050(3), F.A.C. these responses are certified by a professional engineer.

We appreciate your time and attention as this application continues to proceed through the review process. If you have any questions, please contact Edward Garcia of KEYS at (305) 295-1134 or Susan Schumann of FMPA at (407) 355-7767.

Sincerely,
Keys Energy Services

Dan Cassel

Dan Cassel
Director of Generation

Enclosures

cc: Kevin Fleming, FMPA
Susan Schumann, FMPA
Jody Finklea, FMPA
Carl Jansen, General Manager & CEO, KEYS
Edward Garcia, KEYS
Diane Tremor, RS&B
Angela Morrison, HGS
Stanley Armbruster, B&V
Kathleen Forney, USEPA Region 4

FMPA/KEYS

STOCK ISLAND COMBUSTION TURBINE UNIT 4

AIR CONSTRUCTION PERMIT APPLICATION

SUPPLEMENTAL RESPONSES TO REQUEST FOR ADDITIONAL INFORMATION

ENGINEERING CERTIFICATION STATEMENT

I, the undersigned, hereby certify that:

The engineering features of Stock Island Combustion Turbine Unit 4 Project described in these responses to requests for additional information have been prepared, or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles; and,

To the best of my knowledge, the information submitted in the responses is true, accurate, and complete based on reasonable techniques, estimates, materials, and information gathered and evaluated by qualified personnel.

Stanley A. Armbruster

STANLEY A. ARMBRUSTER LICENSE 30562 STATE OF FLORIDA PROFESSIONAL ENGINEER

Name: Stanley A. Armbruster
Florida License No. 30562
Date: February 16, 2005

Black & Veatch
11401 Lamar
Overland Park, Kansas

STANLEY A. ARMBRUSTER LICENSE 30562 STATE OF FLORIDA PROFESSIONAL ENGINEER

Stock Island Combustion Turbine Unit 4 Air Permit Application
Responses to Florida Department of Environmental Protection
Supplemental Request for Additional Information

Based on the meeting between the Florida Department of Environmental Protection (DEP), the US Environmental Protection Agency (EPA) (attended by conference call), and Florida Municipal Power Agency/Keys Energy Services (FMPA/KEYS) on February 3, 2005, FMPA/KEYS is providing the following information to supplement the Responses to Request for Additional Information submitted by KEYS letter of January 14, 2005 and received by the DEP on January 18, 2005.

Issue 1: The DEP requested that FMPA/KEYS provide the projected fuel oil usage by year for the Stock Island Combustion Turbine Unit 4.

Response to Issue 1: Attached are Tables 1 and 1A that provide information on fuel oil usage by year of operation. Table 1 provides, on an annual basis, the expected hours of operation (at any load), the expected amount of fuel oil burned, the equivalent hours at full load, the total amount of NOx produced (at 42 ppm), the amount of NOx removed (assuming reduction from 42 to 5 ppm) and the yearly BACT cost for the NOx removed. The fuel oil usage numbers provided in Table 1 are FMPA/KEYS best estimate of expected usage; however, there are a number of factors and variables which could change the actual fuel oil usage. The fuel oil usage in 2018 is projected to decrease due to the need to install additional generation to meet load growth. The unit installed in 2018 is expected to be more efficient and would dispatch ahead of Unit 4, thus decreasing the expected fuel usage of Unit 4.

The yearly cost for the tons of NOx removed is calculated in Table 1A. The basis of this table is Tables RAI4-2 and RAI4-3 (Average of Additional Bids) provided in the responses to Request for Additional Information. The original values in Table RAI4-3 have been adjusted to reflect the reagent feed based on a 1.1 stoichiometric ratio, as requested by the FDEP, instead of 1.4, as originally submitted. Table 1A represents the cost of operation of the SCR each year for fifteen years assuming a 2.5 % per year escalation. Column C shows the BACT based evaluation from Tables RAI4-2 and RAI4-3 with the reagent feed adjustment. The subsequent columns show the operating and capital recovery costs annually, based on the hours of operation, equivalent full load hours of operation and NOx removed from Table 1. Based on the reduced hours of operation in the early years, the first catalyst replacement is not expected to occur until the fourth year, as indicated in cell G13. The first three years of operation result in annual cost effectiveness values ($/ton removed) of $22,297 to $16,860, even without the additional cost of catalyst replacement. Also, in later years, the cost effectiveness is in the $14,000 to $15,000 range in years of catalyst replacement.

This information clearly shows that SCR is not cost effective and therefore should not be considered as BACT.

Issue 2: The DEP/EPA questioned lost power generation during catalyst replacement, indicating catalyst replacement should be sequenced with combustion turbine (CT) maintenance, reducing the amount of downtime associated with catalyst replacement. Also, the use of the FMPA wholesale rate to calculate the cost of the replacement power was questioned, with the EPA suggesting the use of differential heat rates.

Response to Issue 2: FMPA/KEYS has reviewed the potential of coordinating catalyst replacement with CT maintenance, as shown in Table 2. The catalyst is normally replaced after every 7,000 hours of operation and requires a seven day outage. The CT Hot Section and Combustion Rotable are maintained every 12,500 hours, requiring a two-day outage. In addition, a Major Overhaul is performed every 50,000 hours, requiring an initial two day outage to remove and replace the original engine with a lease engine, followed by an additional two day outage approximately one to two months later to return the shop-refurbished engine to operation. The savings in replacement power by combining the CT maintenance and catalyst replacement is two days out of seven. However, coordinating these two events will result in replacement of the catalyst prior to full use of its life. Typically, approximately 20 % of a catalyst life will be lost. The attached shows that the increased cost of early replacement of the catalyst more than offsets any potential savings in replacement power during the catalyst replacement. On an average annual basis, matching the catalyst replacement to the CT maintenance adds approximately $24,500/yr or $181/ton to the cost effectiveness.

The EPA suggested the use of differential heat rate of power generation, instead of the FMPA wholesale rate, as the more appropriate factor to evaluate for the calculation of loss power generation during the catalyst replacement period. The LM6000 full load operation is 44,705 kW at 9,492 Btu/kWh heat rate per Attachment 1 of the PSD Application. The average full load heat rate of the other three combustion turbines at Stock Island Generating Facility is 14,786 Btu/kWh. The differential heat rate is 5,294 Btu/kWh. The differential fuel cost calculated using the 5,294 Btu/kWh differential heat rate with 44,705 kW/h generation by the other combustion turbines vs CT 4 for 7 days at a fuel cost of $5.24/MMBtu is $105,170, assuming a capacity factor of 50.5 % (4422 full load hours requested in the BACT divided by 8760 hours per year). The use of differential fuel costs due to differential heat rate would decrease the cost effectiveness by $1,000/ton. However, FMPA/KEYS believes the use of the FMPA wholesale rate is more consistent with typical BACT evaluations that are based on replacement power costs.

Issue 3: The DEP and EPA still questioned the use of 7 % interest rate as the basis for the capital recovery factor.

Response to Issue 3: As noted in previous RAI response, the 7 percent interest rate is taken directly from the EPA Air Pollution Control Cost Manual (Manual), January 2002, page 2-13. The 7 percent interest rate is a social interest rate as described in the Manual. The use of the social interest rate is appropriate for BACT analysis as described in the Manual to ensure all BACT evaluations are conducted on a consistent basis. The actual cost of long term bonds for FMPA is approximately 5 percent with the long term interest rates tending to increase. It is very likely that FMPA financing rates will change before FMPA can finance this plant. It is more likely that they will increase as the low rates that have been seen for the last couple of years were last seen more than forty years ago. Most of the bonds FMPA has issued in fixed rate form have had rates in excess of 5 percent.

The 5 percent rate is for a fully insured tax exempt bond issue. The societal cost of tax exempt bonds should reflect the fact that income tax does not flow to the society as a whole as do the benefits of taxable bonds. One way to measure that additional societal cost is to look at the difference in bond rates between tax exempt and taxable bond rates. That difference has been as large as approximately 4 percent, but now has decreased to approximately 2 percent and sometimes even a little lower. Nevertheless adding that differential to the 5 percent bond rate gets back to a rate very close to the 7 percent social rate in the Manual.

Furthermore, FMPA incurs significant actual finance costs associated with tax exempt financing. These additional costs increase the fixed charge rate significantly compared to only the capital recovery factor. FMPA must pay issuance costs including bond insurance. These costs are approximately 2 percent of the bond issue for large bond issues such as for the whole power plant and would be higher on a percentage basis for a bond issue for just the SCR. In addition, FMPA is required to maintain a debt service reserve fund of 6 month's principle and interest. That fund is limited in what it can earn in interest by the Tax Reform Act of 1986 to the bond rate. Negative arbitrage associated with the Reserve Funds adds to the total interest cost, and positive arbitrage is paid to the IRS. The fixed charge rate based on a 5 percent bond rate with a 2 percent bond issuance fee and a 6 month debt service reserve fund earning interest at the bond rate is 0.1006 which compares to the capital recovery factor of the 7 percent social interest rate of 0.1098.

In summary, the social interest rate of 7 percent is reasonable and appropriate and is comparable to FMPA's out of pocket cost with no social adjustments.

Issue 4: The DEP/EPA consider SCR on oil fired units a reliable technology with a three year catalyst life while FMPA/KEYS believes one year is more appropriate based on limited SCR experience on oil fired units.

Response to Issue 4: As noted in the previous RAI responses, there is very limited experience with SCR's on oil fired only units and two of the SCR's have had catalyst failures. To assist the DEP in review of this item, the following summary of contacts made in investigating the suitability of applying a SCR for NO_x control on Stock Island Combustion Turbine Unit 4 is provided:

The following personnel from EPA Region 2 were contacted regarding the PREPA Cambalache Plant.

Mr. Jerod (Jerry) DeGietano – (212) 637-4020 – Mr. Digietano was involved in the initial permitting of the Cambalache Project and was familiar with the failure of their SCR system.

Mr. Steve Riva – (212) 637-4074 – Mr. Riva was familiar with the air permitting at the Cambalache Plant and with the failure of their SCR system.

Mr. Frank Jon – (212) 637-4085 – Mr. Jon is the permit engineer assigned to process the Cambalache permit revision application. He is familiar with the air permitting at the Cambalache Plant and with the problems they had in getting their SCR to operate properly.

Mr. Umesh Dholakia of EPA Region 2 was contacted regarding the permitting of the Virgin Islands Water and Power Authority (VIWAPA) St Thomas Generating Station Unit 23. Mr. Dholakia is the permit engineer for the VIWAPA Unit 23 Project. Mr. Dholakia's contact number is (212) 637-4023.

Mr. Mike Jennings of the New York State Department of Environmental Conservation (NYSDEC) was contacted regarding permitting of the Shoreham facility. Mr. Jennings worked on the permitting of the Shoreham facility. Mr. Jennings' contact number is (518) 402-8403. Mr. Jennings is also aware of SCR problems on a number of LM6000 size combustion turbines in the Long Island area.

Mr. Tom Turner of Turner Environmental was contacted regarding the failure of the catalyst at the Greenport Facility. Mr. Turner's contact number is (800) 933-8385.

Issue 5: DEP/EPA believe that the capital cost estimating contingency should be in the three percent range instead of twenty percent proposed by FMPA/KEYS.

Response to Issue 5: As noted in our responses to the request for additional information, FMPA/KEYS provided justification for the twenty percent level of contingency. To further support this level of contingency, please refer to the attached information from RSMeans Building Construction Cost Data which is used throughout the construction industry to estimate project costs. Page 7 shows suggested levels of contingency as a function of project stage (level of detailed information developed or available). For the conceptual stage, the suggested contingency level is twenty percent. A BACT evaluation is less refined than the conceptual stage. The three percent suggested by the DEP/EPA is only appropriate after completion of design of a project, as noted in our previous responses.

Table 1 - Projected Fuel Usage and Equivalent Operating Hours
Stock Island Combustion Turbine Unit 4

16-Feb-05

A	B	C	D	E	F	G	H
1	Year	Hours of Operation	Gallons Fuel Burned	Equivalent Full Load Hours	NOx Produced in Tons	NOx Removed in Tons	BACT Yearly Cost Effectiveness, $/ton
2							
3	2006	1,905	3,740,000	1,219	42.5	37.4	$ 22,297
4	2007	2,259	4,436,000	1,446	50.4	44.4	$ 19,234
5	2008	2,648	5,200,000	1,695	59.1	52.0	$ 16,860
6	2009	3,107	6,100,000	1,988	69.3	61.0	$ 23,417
7	2010	3,565	7,000,000	2,282	79.5	70.0	$ 13,236
8	2011	3,972	7,800,000	2,542	88.6	78.0	$ 19,771
9	2012	4,329	8,500,000	2,770	96.5	85.1	$ 18,775
10	2013	4,685	9,200,000	2,999	104.5	92.1	$ 10,847
11	2014	5,149	10,110,000	3,295	114.8	101.2	$ 16,961
12	2015	5,704	11,200,000	3,651	127.2	112.1	$ 15,980
13	2016	6,290	12,350,000	4,025	140.3	123.6	$ 15,181
14	2017	7,000	13,567,000	4,422	154.1	135.8	$ 14,456
15	2018	3,565	7,000,000	2,282	79.5	70.0	$ 14,630
16	2019	3,906	7,670,000	2,500	87.1	76.7	$ 23,106
17	2020	4,278	8,400,000	2,738	95.4	84.1	$ 12,870
18	2021	4,685	9,200,000	2,999	104.5	92.1	$ 15,574
19	2022	5,042	9,900,000	3,227	112.4	99.1	$ 15,199
20	2023	5,225	10,260,000	3,344	116.5	102.7	$ 15,182
21	2024	5,755	11,300,000	3,683	128.4	113.1	$ 6,501
22	2025	6,264	12,300,000	4,009	139.7	123.1	$ 14,117
23							
24	BACT Values	7,000	13,567,000	4,422	154.1	135.8	$ 11,793

Table 1A - BACT Yearly Cost Assuming Installation of SCR at Commercial Operation
Stock Island Combustion Turbine Unit 4

16-Feb-05

A	B	C	D	E	F	G	H	I	J	K
1	Cost Item	BACT Evaluation	2006	2007	2008	2009	2010	2011	2012	2013
2										
3	**Total Capital Investment**	$ 4,314,000								
4										
5	Hours of Operation		1,905	2,259	2,648	3,107	3,565	3,972	4,329	4,685
6	Cumulative Hours of Operation		1,905	4,164	6,812	9,919	13,484	17,456	21,785	26,470
7	Equivalent Full Load Operating Hours		1,219	1,446	1,695	1,988	2,282	2,542	2,770	2,899
8										
9	FMPA Wholesale Rate	$ 0.05925	$ 0.05925	$ 0.06065	$ 0.06458	$ 0.06416	$ 0.06762	$ 0.06818	$ 0.06999	$ 0.07139
10	Catalyst Replacement Year		No	No	No	Yes	No	Yes	Yes	No
11										
12	**Direct Annual Cost**									
13	Catalyst Replacement	$ 383,000	$ -	$ -	$ -	$ 412,449	$ -	$ 433,329	$ 444,163	$ -
14	O&M	$ 70,000	$ 70,000	$ 71,750	$ 73,544	$ 75,382	$ 77,267	$ 79,199	$ 81,179	$ 83,208
15	Reagent Feed	$ 49,500	$ 13,641	$ 16,584	$ 19,926	$ 23,960	$ 28,182	$ 32,188	$ 35,953	$ 39,887
16	Power Consumption	$ 36,000	$ 9,924	$ 12,049	$ 15,039	$ 17,528	$ 21,198	$ 23,817	$ 26,643	$ 29,414
17	Lost Power Generation									
18	Backpressure	$ 112,000	$ 30,875	$ 37,486	$ 46,789	$ 54,531	$ 65,951	$ 74,096	$ 82,880	$ 91,511
19	Catalyst Replacement	$ 241,000	$ -	$ -	$ -	$ 117,338	$ -	$ 159,440	$ 178,361	$ -
20	Annual Distribution Check	$ 65,000	$ 55,000	$ 56,375	$ 57,784	$ 59,229	$ 60,710	$ 62,227	$ 63,783	$ 65,378
21	Total Direct Costs	$ 946,500	$ 179,440	$ 194,244	$ 213,083	$ 760,416	$ 253,308	$ 864,296	$ 912,971	$ 309,397
22										
23	**Indirect Annual Costs**									
24	Overhead	$ 42,000	$ 42,000	$ 43,050	$ 44,126	$ 45,229	$ 46,360	$ 47,519	$ 48,707	$ 49,925
25	Administrative Charges	$ 93,000	$ 93,000	$ 95,325	$ 97,708	$ 100,151	$ 102,655	$ 105,221	$ 107,851	$ 110,548
26	Property Taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Insurance	$ 46,000	$ 46,000	$ 47,150	$ 48,329	$ 49,537	$ 50,775	$ 52,045	$ 53,346	$ 54,680
28	Capital Recovery	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000
29	Total Indirect Annual Costs	$ 655,000	$ 655,000	$ 659,525	$ 664,163	$ 668,917	$ 673,790	$ 678,785	$ 683,905	$ 689,152
30										
31	**Total Annualized Cost**	$ 1,601,500	$ 834,440	$ 853,769	$ 877,246	$ 1,429,334	$ 927,098	$ 1,543,081	$ 1,596,876	$ 998,549
32										
33	**Tons Removed**	135.6	37.4	44.4	52.0	61.0	70.0	78.0	85.1	92.1
34										
35	**Cost Effectiveness, $/ton**	$ 11,793	$ 22,297	$ 19,234	$ 16,860	$ 23,417	$ 13,236	$ 19,771	$ 18,775	$ 10,847

A	B	L	M	N	O	P	Q	R	S	T	U	V	W
1	Cost Item	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2													
3	**Total Capital Investment**												
4													
5	Hours of Operation	5,149	5,704	6,290	7,000	3,565	3,906	4,278	4,685	5,042	5,225	5,755	6,284
6	Cumulative Hours of Operation	31,619	37,323	43,613	50,613	54,177	58,084	62,362	67,047	72,089	77,314	83,069	89,333
7	Equivalent Full Load Operating Hours	3,295	3,651	4,025	4,422	2,282	2,500	2,738	2,999	3,227	3,344	3,683	4,009
8													
9	FMPA Wholesale Rate	$ 0.07306	$ 0.07480	$ 0.07736	$ 0.07912	$ 0.08138	$ 0.08378	$ 0.08540	$ 0.08697	$ 0.08959	$ 0.09129	$ 0.09302	$ 0.09479
10	Catalyst Replacement Year	Yes	Yes	Yes	Yes	No	Yes	No	Yes	Yes	Yes	No	Yes
11													
12	**Direct Annual Cost**												
13	Catalyst Replacement	$ 466,848	$ 478,315	$ 490,272	$ 502,529	$ -	$ 527,970	$ -	$ 554,698	$ 568,566	$ 582,780	$ -	$ 612,283
14	O&M	$ 85,288	$ 87,420	$ 89,606	$ 91,846	$ 94,142	$ 96,496	$ 98,908	$ 101,381	$ 103,915	$ 106,513	$ 109,176	$ 111,906
15	Reagent Feed	$ 44,928	$ 51,016	$ 57,661	$ 64,927	$ 34,337	$ 38,564	$ 43,290	$ 48,598	$ 53,804	$ 56,942	$ 64,281	$ 71,719
16	Power Consumption	$ 33,080	$ 37,519	$ 42,787	$ 48,073	$ 25,512	$ 28,778	$ 32,127	$ 35,833	$ 39,721	$ 41,947	$ 47,077	$ 52,216
17	Lost Power Generation												
18	Backpressure	$ 102,916	$ 116,725	$ 133,118	$ 149,560	$ 79,371	$ 89,533	$ 99,950	$ 111,482	$ 123,578	$ 130,502	$ 146,461	$ 162,451
19	Catalyst Replacement	$ 221,450	$ 251,168	$ 286,436	$ 321,821	$ -	$ 192,655	$ -	$ 239,884	$ 265,913	$ 280,812	$ -	$ 349,560
20	Annual Distribution Check	$ 67,012	$ 68,687	$ 70,405	$ 72,165	$ 73,969	$ 75,818	$ 77,714	$ 79,656	$ 81,648	$ 83,689	$ 85,781	$ 87,926
21	Total Direct Costs	$ 1,021,321	$ 1,090,851	$ 1,170,283	$ 1,250,921	$ 307,331	$ 1,049,814	$ 351,989	$ 1,171,533	$ 1,236,945	$ 1,283,184	$ 452,776	$ 1,448,061
22													
23	**Indirect Annual Costs**												
24	Overhead	$ 51,173	$ 52,452	$ 53,764	$ 55,108	$ 56,485	$ 57,897	$ 59,345	$ 60,829	$ 62,349	$ 63,908	$ 65,506	$ 67,143
25	Administrative Charges	$ 113,311	$ 116,144	$ 119,048	$ 122,024	$ 125,075	$ 128,202	$ 131,407	$ 134,692	$ 138,059	$ 141,510	$ 145,048	$ 148,674
26	Property Taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Insurance	$ 56,047	$ 57,448	$ 58,884	$ 60,356	$ 61,865	$ 63,412	$ 64,997	$ 66,622	$ 68,287	$ 69,994	$ 71,744	$ 73,538
28	Capital Recovery	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ -	$ -	$ -	$ -	$ -
29	Total Indirect Annual Costs	$ 694,531	$ 700,044	$ 705,695	$ 711,488	$ 717,425	$ 723,510	$ 729,748	$ 262,142	$ 268,696	$ 275,413	$ 282,298	$ 289,356
30													
31	**Total Annualized Cost**	$ 1,715,852	$ 1,790,895	$ 1,875,979	$ 1,962,409	$ 1,024,756	$ 1,773,324	$ 1,081,737	$ 1,433,675	$ 1,505,640	$ 1,558,597	$ 735,074	$ 1,737,416
32													
33	**Tons Removed**	101.2	112.1	123.6	135.8	70.0	76.7	84.1	92.1	99.1	102.7	113.1	123.1
34													
35	**Cost Effectiveness, $/ton**	$ 16,961	$ 15,980	$ 15,181	$ 14,456	$ 14,630	$ 23,106	$ 12,870	$ 15,574	$ 15,199	$ 15,182	$ 6,501	$ 14,117

Table 2 - Potential Saving/Cost of Matching CT Maintenance and Catalyst Replacement
Stock Island Combustion Turbine Unit 4

16-Feb-05

Catalyst Life is 7,000 hours of Operation.
CTG Maintenance: Hot Section & Combustion Rotable Every 12,500 hours with Major Overhaul every 50,000 hours
Overlaping CT Maintenance and Catalyst Replacement: 2 Days

A	B	C	D	E	F	G	H	I	J
1	Year	Hours of Operation	Cumulative Hours of Operation (Also, Catalyst Replacement Hours if Not Matching CT Maintenance)	CTG Maintenance Hours	Catalyst Replacement Hours to Match CT Maintenance	Catalyst Replacement Cost Matching CT Maintenance	Catalyst Replacement Lost Generation Matching CT Maintenance	Catalyst Replacement Cost Not Matching CT Maintenance	Catalyst Replacement Lost Generation Not Matching CT Maintenance
2									
3	2006	7,000	7,000		7,000	$ 383,000	$ 241,000	$ 383,000	$ 241,000
4	2007	7,000	14,000	12,500	12,500	$ 383,000	$ 172,143	$ 383,000	$ 241,000
5	2008	7,000	21,000		19,500	$ 383,000	$ 241,000	$ 383,000	$ 241,000
6	2009	7,000	28,000	25,000	25,000	$ 383,000	$ 172,143	$ 383,000	$ 241,000
7	2010	7,000	35,000		32,000	$ 383,000	$ 241,000	$ 383,000	$ 241,000
8	2011	7,000	42,000	37,500	37,500	$ 383,000	$ 172,143	$ 383,000	$ 241,000
9	2012	7,000	49,000		44,500	$ 383,000	$ 241,000	$ 383,000	$ 241,000
10	2013	7,000	56,000	50,000	50,000	$ 383,000	$ 172,143	$ 383,000	$ 241,000
11	2014	7,000	63,000	62,500	57,000	$ 383,000	$ 241,000	$ 383,000	$ 241,000
12					62,500	$ 383,000	$ 172,143		
13	2015	7,000	70,000		69,500	$ 383,000	$ 241,000	$ 383,000	$ 241,000
14	2016	7,000	77,000	75,000	75,000	$ 383,000	$ 172,143	$ 383,000	$ 241,000
15	2017	7,000	84,000		82,000	$ 383,000	$ 241,000	$ 383,000	$ 241,000
16	2018	7,000	91,000	87,500	87,500	$ 383,000	$ 172,143	$ 383,000	$ 241,000
17	2019	7,000	98,000		94,500	$ 383,000	$ 241,000	$ 383,000	$ 241,000
18	2020	7,000	105,000	100,000	100,000	$ 383,000	$ 172,143	$ 383,000	$ 241,000
19	2021	7,000	112,000		107,000	$ 383,000	$ 241,000	$ 383,000	$ 241,000
20	2022	7,000	119,000	112,500	112,500	$ 383,000	$ 172,143	$ 383,000	$ 241,000
21	2023	7,000	126,000	125,000	119,500	$ 383,000	$ 241,000	$ 383,000	$ 241,000
22					125,000	$ 383,000	$ 172,143		
23	2024	7,000	133,000		132,000	$ 383,000	$ 241,000	$ 383,000	$ 241,000
24	2025	7,000	140,000	137,500	137,500	$ 383,000	$ 172,143	$ 383,000	$ 241,000
25									
26			Cumulative Totals			$ 8,426,000	$ 4,544,571	$ 7,660,000	$ 4,820,000
27			Average Yearly Value			$ 421,300	$ 227,229	$ 383,000	$ 241,000
28			Total Average Yearly Cost				$ 648,529		$ 624,000
29									
30			**Yearly Average Cost of Matching CT**						
31			**Maintenance and Catalyst Replacement**				**$ 24,529**		**Base**
32									
33			**Tons Removed**				**135.8**		
34			**Added Cost Effectiveness, $/Ton**				**$ 181**		

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2005

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01100 | Summary

		01107 | Professional Consultant	Crew	Daily Output	Labor-Hours	Unit	2005 Bare Costs Mat.	Labor	Equip.	Total	Total Incl O&P	
700	1400	Crew for roadway layout, 4 person crew	A-8	1	32	Day		1,150	61	1,211	1,850	700
	1500	Aerial surveying, including ground control, minimum fee, 10 acres				Total					5,700	
	1510	100 acres									9,500	
	1550	From existing photography, deduct				↓					1,370	
	1600	2' contours, 10 acres				Acre					460	
	1650	20 acres									315	
	1800	50 acres									95	
	1850	100 acres									85	
	2000	1000 acres									17.85	
	2050	10,000 acres				↓					11.50	
	2150	For 1' contours and										
	2160	dense urban areas, add to above				Acre					40%	
	3000	Inertial guidance system for										
	3010	locating coordinates, rent per day				Ea.					4,000	

01200 | Price & Payment Procedures

		01250 | Contract Modification Procedures	Crew	Daily Output	Labor-Hours	Unit	2005 Bare Costs Mat.	Labor	Equip.	Total	Total Incl O&P	
200	0010	**CONTINGENCIES** for estimate at conceptual stage				Project					20%	200
	0050	Schematic stage									15%	
	0100	Preliminary working drawing stage (Design Dev.)									10%	
	0150	Final working drawing stage				↓					3%	
300	0010	**CREWS** For building construction, see How To Use This Book										300
500	0010	**JOB CONDITIONS** Modifications to total										500
	0020	project cost summaries										
	0100	Economic conditions, favorable, deduct				Project					2%	
	0200	Unfavorable, add									5%	
	0300	Hoisting conditions, favorable, deduct									2%	
	0400	Unfavorable, add									5%	
	0500	General Contractor management, experienced, deduct									2%	
	0600	Inexperienced, add									10%	
	0700	Labor availability, surplus, deduct									1%	
	0800	Shortage, add									10%	
	0900	Material storage area, available, deduct									1%	
	1000	Not available, add									2%	
	1100	Subcontractor availability, surplus, deduct									5%	
	1200	Shortage, add									12%	
	1300	Work space, available, deduct									2%	
	1400	Not available, add				↓					5%	
600	0010	**OVERTIME** For early completion of projects or where R01100-110										600
	0020	labor shortages exist, add to usual labor, up to				Costs		100%				

		01255 | Cost Indexes	Crew	Daily Output	Labor-Hours	Unit	Mat.	Labor	Equip.	Total	Total Incl O&P	
200	0010	**CONSTRUCTION COST INDEX** (Reference) over 930 zip code locations in										200
	0020	The U.S. and Canada, total bldg cost, min. (Clarksdale, MS)				%					66.80%	
	0050	Average									100%	
	0100	Maximum (New York, NY)				↓					131.90%	
400	0010	**HISTORICAL COST INDEXES** (Reference) Back to 1955										400

Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

February 17, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33401-6100

Re: Second Request for Additional Information
Combustion Turbine Unit 4 – GE LM6000 SPRINT
File No. 0870003-007-AC (PSD-FL-348)

Dear Mr. Cassel:

On January 18, 2005 the Department received the KEYS Energy response to our request for additional information dated November 10, 2004. On February 16 we received via electronic mail an update to that response based on our meeting with your representatives (and EPA by phone) on February 2. We have not yet reviewed that information.

Based on the response received on January 18, we require additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

Cost effectiveness should also be calculated based on the uncontrolled NO_X emissions prior to water injection. The starting value, for example, might be greater than 100 ppm. The calculation should include a credit for the additional power generated as a result of the increased mass flow when injecting water. This issue was discussed with your representatives at our meeting of February 2.

Attached is a fact sheet for 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines under development by EPA. We understand from our EPA Region 4 permitting contact that a rule will be proposed this month in the Federal Register.

NSPS rules provide a floor for BACT determinations. The draft of the rule proposes a limit of 1.2 lb NO_X/megawatt-hr for new oil-fired combustion turbines such as the one proposed by KEYS Energy. Based on the application, it appears that emissions from KEYS Energy Unit 4 will be greater than 1.5 lb NO_X/MWH. Both values are significantly greater than typical BACT determinations for continuous duty combustion turbines. We are not allowed to issue BACT determinations for a combustion turbine that are less than the corresponding NSPS.

We will forward any additional comments received from EPA Region 4.

At the meeting, we cited a number of assumptions and conclusions by KEYS Energy with which we do not agree and why we don't agree. It is not necessary to enumerate them at this time. We have limited this request for additional information to just a few issues.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1), F.A.C., "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department ... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions, please call me at 850/921-9523.

Sincerely,

A A Linero 2/17

A. A. Linero, Administrator
South Air Permitting Section

Cc: Ron Blackburn, DEP
Edward Garcia, Keys Energy Services
Stanley Armbruster, P.E., Black & Veatch
Susan Schumann, FMPA
Jim Little, EPA Region 4
John Bunyak, National Park Service

FACT SHEET

PROPOSED RULE SETTING THE STANDARDS OF PERFORMANCE FOR STATIONARY COMBUSTION TURBINES

ACTION

- On February 9, 2005, the Environmental Protection Agency (EPA) proposed a rule that would reduce emissions of air pollutants from new stationary combustion turbines. These proposed requirements would apply to new turbines with a peak rated power output greater than or equal to 1 megawatt (MW). These turbines are used at facilities such as power plants, pipeline compressor stations, and chemical and manufacturing plants.

- These proposed standards, known as New Source Performance Standards (NSPS), would apply to new turbines and reflect changes in nitrogen oxides (NO_x) emission control technologies and turbine design since the NSPS for stationary combustion turbines were originally promulgated in 1979.

- New, modified and reconstructed turbines would have to comply with the proposed rule. A new turbine is defined as one that commences construction after the date of proposal and would have to comply upon startup. Modified or reconstructed sources would have up to 6 months after the rule is final, or 6 months after startup, whichever is later, to demonstrate compliance with the new standards.

- The proposed rule would reduce emissions of NO_x and sulfur dioxide (SO_2).

- The proposed rule would require that new turbines meet the following emission limits for NO_x:
  - Natural gas-fired turbines below 30 MW meet an emission limit of 132 nanograms per Joule (ng/J) [1.0 pound per megawatt-hour (lb/MW-hr)].
  - Oil and other fuel-fired turbines below 30 MW meet an emission limit of 234 ng/J (1.9 lb/MW-hr).
  - Natural gas-fired turbines greater than or equal to 30 MW meet an emission limit of 50 ng/J (0.39 lb/MW-hr).
  - Oil and other fuel-fired turbines greater than or equal to 30 MW meet an emission limit of 146 ng/J (1.2 lb/MW-hr).

- The proposed standard for SO_2 is the same for all turbines, regardless of size and fuel type. All new turbines would be required to meet an emission limit of 73 ng/J (0.58 lb/MW-hr). Alternatively, a fuel sulfur content limit of 0.05 percent by weight [500 parts per million (ppmw)] could be met.

- EPA expects that most owners or operators of new turbines would be able to comply with the NO_x limit without installing add-on emissions controls. Most new turbines already utilize lean premix technology, which has inherently low NO_x emissions. A few turbines may need to install a selective catalytic reduction (SCR) control device to meet the NO_x limit.

- EPA expects that all owners and operators of new turbines will comply with the option of demonstrating low sulfur content of their fuels rather than stack testing for SO_2. Fuel oil and pipeline natural gas contain low levels of sulfur and are widely available.

- EPA estimates that 355 new stationary combustion turbines would be subject to the rule, as proposed, by the end of the 5th year after the final rule takes effect.

- Comments may be submitted on the proposed action for 60 days following publication of the proposed rule in the Federal Register.

HEALTH/ENVIRONMENTAL BENEFITS

- The proposed rule would provide improvements in protecting human health and the environment by reducing pollutant emissions. The EPA estimates that the total pollutant reductions will be over 830 tons per year of criteria pollutants in the 5th year after the rule is final. The proposed rule would reduce NO_x and SO_2 emissions limits by over 80 and 93 percent, respectively.

- An output-based standard relates the emissions to the productive output of the process; in this case, pounds of emissions are related to the power output, or MW-hour. The output-based standards in the proposed rule would allow owners and operators the flexibility to meet their emission limit targets by increasing the efficiency of their turbines. The use of more efficient technologies reduces fossil fuel use, and reduces environmental impacts associated with the production and use of fossil fuels.

- Pollutants such as NO_x and SO_2 may cause both temporary and long-term respiratory symptoms, such as shortness of breath, changes in airway responsiveness, and increased susceptibility to respiratory infection.

- Nitrogen oxides can react in the air to form ground-level ozone. Ozone can cause coughing, shortness of breath, and aggravate asthma, and other chronic lung diseases such as emphysema and bronchitis. Ozone can lead to reduced lung function in both children and adults.

- NO_x and SO_2 also can form fine particle pollution. Exposure to fine particle pollution is associated with significant adverse health effects including shortness of breath, bronchitis, asthma attacks, heart attacks and premature death.

- Both NO_x and SO_2 are major precursors to acid rain, which, when deposited, are associated with acidification of soil and surface water.

COST

- EPA estimates the total nationwide annual costs for the rule, as proposed, to be \$3.4

million in the 5th year.

BACKGROUND

- The Clean Air Act requires EPA to promulgate NSPS for stationary combustion turbines. The standards must consider emission control technologies available and costs of control.

- New source performance standards are a statutory requirement under section 111 of the Clean Air Act. The original NSPS for stationary combustion turbines were promulgated under subpart GG of 40 CFR part 60 in 1979. Under the Clean Air Act, the Administrator is required to review the standards at least every 8 years, and revise the standards as appropriate.

- Since EPA originally promulgated new source performance standards for stationary gas turbines in 1979, technological advances have led to improvements in:
  - nitrogen oxide emissions control devices,
  - emissions monitoring devices,
  - emissions test methods,
  - combustion efficiency and turbine design, and
  - the composition of fuels used for gas turbines.

- The proposed standards reflect the performance and emissions of today's new stationary combustion turbines without the use of add-on controls.

FOR MORE INFORMATION

- To download the proposed rule from EPA's web site, go to "Recent Actions" at the following address: *http://www.epa.gov/ttn/oarpg.*

- For further information about the rule, contact Mr. Jaime Pagán at EPA's Office of Air Quality Planning and Standards at 919-541-5340.

- For other combustion-related regulations, visit EPA's Combustion Related Rules page at: *http://www.epa.gov/ttn/combust/list.html.*

Adams, Patty

From: Mulkey, Cindy

Sent: Friday, February 18, 2005 2:34 PM

To: Adams, Patty

Subject: FW: Request for Additional Information

Cindy Mulkey
Engineer
Bureau of Air Regulation
Permitting South
(850) 921-8968
FAX (850)921-9533
SC 291-8968

-----Original Message-----
From: Linero, Alvaro
Sent: Thursday, February 17, 2005 2:55 PM
To: 'dan.cassel@Keysenergy.com'
Cc: 'Susan.schumann@fmpa.com'; 'armbrustersa@bv.com'; Blackburn, Ron; 'rollinsmr@bv.com'; 'Edward.Garcia@KeysEnergy.com'; Mulkey, Cindy; Vielhauer, Trina; 'Forney.Kathleen@epamail.epa.gov'; 'Little.James@epamail.epa.gov'
Subject: RE: Request for Additional Information

Attached is our request for additional information.

Thank you

Al Linero

energy services

(305) 295-1000
1001 James Street
PO Box 6100
Key West, FL 33041-6100
www.KeysEnergy.com

UTILITY BOARD OF THE CITY OF KEY WEST

April 12, 2005

Al Linero,
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
2600 Blair Stone Road MS 5500
Tallahassee, FL 32399-2400
(850) 921-9523

Subject: Stock Island Power Plant Construction Permit Application
Response to Second Request for Additional Information
File No. 0870003-007-AC (PSD-FL-348)

Dear Mr. Linero:

Keys Energy Services (KEYS) respectfully submits the enclosed responses to your February 17, 2005 Second Request for Additional Information regarding the FMPA/KEYS Stock Island Power Plant Air Construction Permit Application. Also enclosed are revised pages to amend the application based on discussions between FDEP, FMPA, and KEYS in the March 17, 2005 meeting and subsequent telephone conversations between Trina Vielhauer and Susan Schumann. This amendment reflects the understanding between the FDEP and FMPA/KEYS that an operational limit of 2,500 hours per year results in a BACT determination of water injection to 42 ppm for NOx control, based on cost effectiveness. With the 2,500 hours of operation limit, the project is no longer subject to PSD for sulfur related emissions. The amendment also incorporates operation down to 20% load, and the associated results from the additional modeling analyses are included. As required by Rule 62-4.050(3), F.A.C. these responses and the amended application are certified by a professional engineer.

We appreciate your time and attention as this application continues to proceed through the review process. If you have any questions, please contact Edward Garcia of KEYS at (305) 295-1134 or Susan Schumann of FMPA at (407) 355-7767.

Sincerely,
Keys Energy Services

Dan Cassel

Dan Cassel
Director of Generation

Enclosures

FMPA/KEYS
Mr. Al Linero

April 13, 2005

cc: Jim Hay, FMPA
Susan Schumann, FMPA
Jody Finklea, FMPA
Carl Jansen, KEYS
Lynne Tejeda, KEYS
Edward Garcia, KEYS
Diane Tremor, RS&B
Angela Morrison, HGS
Stanley Armbruster, B&V
Kathleen Forney, USEPA Region 4
J. Bunyak, NPS
R. Blackburn, SP

FMPA/KEYS

STOCK ISLAND COMBUSTION TURBINE UNIT 4

AIR CONSTRUCTION PERMIT APPLICATION

RESPONSES TO SECOND REQUEST FOR ADDITIONAL INFORMATION

ENGINEERING CERTIFICATION STATEMENT

I, the undersigned, hereby certify that:

The engineering features of Stock Island Combustion Turbine Unit 4 Project described in these responses to requests for additional information have been prepared, or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles; and,

To the best of my knowledge, the information submitted in the responses is true, accurate, and complete based on reasonable techniques, estimates, materials, and information gathered and evaluated by qualified personnel.

Stanley A. Armbruster

Name: Stanley A. Armbruster
Florida License No. 30562
Date: April 13, 2005

Black & Veatch
11401 Lamar
Overland Park, Kansas

STANLEY A. ARMBRUSTER
LICENSE
30562
STATE OF
FLORIDA
PROFESSIONAL ENGINEER

Stock Island Combustion Turbine Unit 4 Air Permit Application
Responses to Florida Department of Environmental Protection
Second Request for Additional Information

The following information is provided in response to the Department's Second Request for Additional Information, dated February 17, 2005.

RAI Issue 1: Cost effectiveness should also be based on the uncontrolled NOx emissions prior to water injection. The starting value for example, might be greater than 100 ppm. The calculation should include a credit for the additional power generated as a result of the increased mass flow when injecting water. This issue was discussed with your representatives at our meeting of February 2.

RAI Issue 1 Response: FMPA/KEYS contacted General Electric (GE) requesting information on a LM6000 unit without water injection. GE indicated they do not manufacture such a unit and the production of such a unit would require a redesign of the combustion system. However, they did provide performance of the existing unit with the water injection turned off. They indicated that the unit should not be operated in this mode and such operation may result in damage to the unit. With the NOx water injection turned off, the unit would produce 316 ppm NOx (449 lb/hr) at full load when operating at 78 F (average annual temperature being used in the BACT). The GE performance information is attached. Based on this information, FMPA/KEYS developed additional NOx removal cost evaluations as requested by the DEP and these are show in Table SRAI-1 which is attached. Table SRAI-1 is based on operation at full load for 2,500 hours per year. The following describes the information provided,

- Column C represents the case of no NOx control, which is the case of operation without water injection. For the purposes of this response, this is considered the base case. It should be noted that in this case, the output is approximately 10 % less than the water injection case and thus the hours of operation were increased by approximately 10 % to obtain comparable annual power generation as was requested in the BACT evaluation with water injection.
- Column D represents the costs associated with providing water injection to control NOx to 42 ppm and costs are provided on an incremental basis as compared to the costs in Column C. As noted in Table SRAI-1, water injection increases the unit output by approximately 4 MW. Also, the water injection increases the heat rate by 236 Btu/kWh. There is no NOx removal in this case, but 533.1 tons per year of NOx is not produced as compared to the case of no water injection. The benefits of the increase in output out weigh any additional capital and operating cost, thus resulting in a negative value for cost effectiveness. This would further support GE's decision to not manufacture a unit without water injection for NOx control.
- Column E represents the original incremental BACT analysis presented in the PSD applications, adjusted to 2,500 hours of full load operation instead of 4,422 hours, and controls NOx emissions to 5 ppm with SCR being added to the water injection case in Column D.

- Column F represents the costs obtained by an average analysis approach in that it sums the costs of the two incremental analyses in Columns D and E. This essentially compares the case of NOx control by water injection and SCR to the case of no control of NOx.

Relative to the applicability of average and incremental economic evaluations, please refer to EPA's draft NSR Workshop Manual (Oct. 1990). Section B explains that various control options and combinations of options should be considered in a BACT analysis, e.g., wet injection and wet injection plus SCR. The average cost effectiveness in $/ton should be considered. The "incremental" cost effectiveness is also to be considered (see page B.41), demonstrating the differences in cost effectiveness between dominant control options. "The incremental cost effectiveness should be examined in combination with the average cost effectiveness in order to justify elimination of a control option."

FMPA/KEYS have been focusing only on the incremental cost effectiveness of using SCR, which is the appropriate approach based on the manual and previous BACT determinations made by the FDEP. It has also been our consultant's experience that the incremental approach is used and the average number is typically not even calculated. We have provided this average cost effectiveness at DEP's request, but the determination of BACT should be on an incremental basis, based only on the applicant's proposed generating unit. The incremental cost of SCR installation on Combustion Turbine Unit 4 which already has water injection is $14,143/ton and is not cost effective. Thus, BACT for NOx control is water injection.

RAI Issue 2: Attached is a fact sheet for 40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines under development by EPA. We understand from our EPA Region 4 permitting contact that a rule will be proposed this month in the Federal Register.

NSPS rules provide a floor for BACT determinations. The draft of the rule proposes a limit of 1.2 lb NOx/megawatt-hr for new oil-fired combustion turbines such as the one proposed by KEYS Energy. Based on the application, it appears that emissions from KEYS Energy Unit 4 will be greater than 1.5 lb NOx/MWH. Both values are significantly greater than typical BACT determinations for continuous duty combustion turbines. We are not allowed to issue BACT determinations for a combustion turbine that are less than the corresponding NSPS.

RAI Issue 2 Response: KEYS/FMPA believes that the applicable NSPS rules are those issued in 1979 for the following reasons:

1. Applicability of the Proposed New Source Performance Standard (NSPS) for Stationary Combustion Turbines, 70 Federal Register 8314 (February 18, 2005)

As we have been discussing with the Department, and as previously provided in draft form, please find attached a copy of the executed contract between GE Packaged Power, Inc. (GE), and the Florida Municipal Power Agency (FMPA) dated February 18, 2005, whereby GE has agreed to construct a nominal 45 megawatt simple-cycle, oil-fired LM6000 PC Sprint combustion turbine to be installed at Stock Island, Key West, Florida, and FMPA has agreed to pay $14,243,009 in exchange for the turbine (with penalties associated with cancellation of the contract). We understand that because the proposed NSPS applies only to combustion turbines that are constructed, modified, or reconstructed after February 18, 2005, and the attached contract demonstrates that FMPA commenced construction on or before February 18, 2005, the new NSPS would not apply to the Stock Island combustion turbine. Please confirm in writing that our understanding on this point is correct, consistent with our meetings and conversations, and that FMPA/KEYS Stock Island Combustion Turbine Unit 4 has begun construction prior to the rule effective date for the purposes of NSPS Subpart KKKK.

2. NSPS as Floor for BACT

Your letter states that the NSPS rules provide a floor for BACT determinations, and that the Department is not allowed to issue BACT determinations for a combustion turbine that are less stringent than the corresponding NSPS. As you know, the proposed NSPS Subpart KKKK applicable to combustion turbines was formally proposed in the Federal Register on February 18, 2005. It will not become final until some time in the future; probably six months to over a year from now, or longer. The federal definition of BACT found at 40 CFR 52.21(b)(12), which is not applicable to this project because of Florida's approved PSD program, provides that the BACT shall not be less stringent than an applicable NSPS. As discussed in Item 1 above, proposed NSPS Subpart KKKK is not applicable to Combustion Turbine Unit 4 and, as such, under the Federal definition does not provide the floor for a BACT determination for Combustion Turbine Unit 4.

Rule 62-212.400(6)(a).1, F.A.C. provides that the Department shall give consideration to NSPS standards when making a BACT determination. While certainly the Department could consider technology in a proposed NSPS and would have to consider technology applicable under a final NSPS, there is no requirement under Florida's rules requiring that a BACT be no less stringent than a proposed NSPS. In addition, this particular proposed NSPS does not require the application of SCR and the limits established in proposed Subpart KKKK are in fact based on a NOx emissions level of 42 ppmvd at 15 percent oxygen (the same emissions level proposed for Combustion Turbine Unit 4 with water injection for NOx control) when firing fuel oil (no add-on controls). The proposed standard becomes difficult to meet for large simple cycle combustion turbines firing fuel oil because the output based standard is based on the efficiency of a combined cycle unit, not a simple cycle unit. This flaw in the development of the standards is acknowledged in the preamble to the proposed rule and EPA asks for comments on this issue. In summary, the NOx control technology of water injection proposed as BACT for Combustion Turbine Unit 4 matches the control technology basis of proposed NSPS Subpart KKKK even though the proposed NSPS Subpart KKKK output based standard, which is based on a combined cycle unit, should not be considered BACT for the simple cycle Combustion Turbine Unit 4.

Table SRAI - 1
NOx Emissions Control Alternatives - Cost Effectiveness Evaluation[1]
Stock Island Combustion Turbine Unit 4

13-Apr-05

A	B	C	D	E	F	G
1	Cost Item	No NOx Control	NOx Control By Water Injection Vs No Control (Incremental Analysis)	NOx Control by SCR and Water Injection Vs Water Injection Only (Incremental Analysis)	NOx Control by SCR and Water Injection Vs No Control (Average Analysis)	Remarks
2						
3	**CAPITAL COSTS**					
4	**Direct Capital Costs**					
5	SCR System	Base	$ -	$ 1,989,000	$ 1,989,000	Average of Vendor Quotes
6	Catalyst Reactor Housing	Base	$ -	Included	Included	
7	Control/Instrumentation	Base	$ 25,000	$ 123,000	$ 148,000	Estimated
8	Ammonia (Injection/Dilution/Storage	Base	$ -	Included	Included	
9	Water Injection Equipment	Base	$ 80,000	$ -	$ 80,000	Estimated
10	Water Storage Tank	Base	$ 265,000	$ -	$ 265,000	Estimated
11	**Purchased Equipment Cost (PEC)**	Base	$ 370,000	$ 2,112,000	$ 2,482,000	
12	Sales Tax	$ -		$ -	$ -	Not Applicable to FMPA
13	Freight	Base	$ 51,800	$ 295,000	$ 346,800	14 % of PEC
14	**Total Purchased Equipment Cost (TPEC)**	Base	$ 421,800	$ 2,407,000	$ 2,828,800	
15	**Direct Installation Costs**					
16	Foundation and Supports	Base	$ 34,000	$ 193,000	$ 227,000	8% of TPEC
17	Handling and Erection	Base	Included Above	$ 337,000	$ 337,000	14% of TPEC
18	Electrical	Base	$ 17,000	$ 96,000	$ 113,000	4% of TPEC
19	Piping	Base	Included Above	$ 48,000	$ 48,000	2% of TPEC
20	Insulation	Base	$ 4,218	$ 24,000	$ 28,218	1% of TPEC
21	Painting	Base	Included Above	$ 24,000	$ 24,000	1% of TPEC
22	Total (Balance of Plant)	Base	$ 55,218	$ 722,000	$ 777,218	
23	**Total Direct Cost (IDC)**	Base	$ 477,018	$ 3,129,000	$ 3,606,018	
24	**Indirect Capital Costs**					
25	Contingency	Base	$ 95,000	$ 626,000	$ 721,000	20 % of DC
26	Engineering and Supervision	Base	$ 48,000	$ 313,000	$ 361,000	10 % of DC
27	Construction & Field Expenses	Base	$ 24,000	$ 156,000	$ 180,000	5 % of DC
28	Construction Fee	Base	$ 48,000	$ 313,000	$ 361,000	10 % of DC
29	Start-up Assistance	Base	$ 10,000	$ 63,000	$ 73,000	2 % of DC
30	Performance Test	Base	$ 5,000	$ 31,000	$ 36,000	1 % of DC
31	**Total Indirect Capital Costs (IC)**	Base	$ 230,000	$ 1,502,000	$ 1,732,000	
32	**Installed Cost (DC + IC)**	Base	$ 707,018	$ 4,631,000	$ 5,338,018	
33	Less SCR Catalyst Cost	Base	$ -	$ (317,000)	$ (317,000)	
34	**Total Capital Investment**	Base	$ 707,018	$ 4,314,000	$ 5,021,018	
35						
36						
37	**ANNUAL COSTS**					
38	**Direct Annual Cost**					
39	Catalyst Replacement	Base	$ -	$ 145,182	$ 145,182	
40	O&M	Base	$ 13,000	$ 70,000	$ 83,000	3 % of TPC
41	Water Usage	Base	$ 184,500	$ -	$ 184,500	Water - 41 gpm at $0.03/gallon
42	Reagent Feed (Water and/or Ammonia)	Base	$ -	$ 27,985	$ 27,985	1.1 Stoichiometric Ratio
43	Power Consumption	Base	$ 3,703	$ 20,353	$ 24,056	
44	Lost Power Generation					
45	Water Injection Equipment	Base	$ (592,500)	$ -	$ (592,500)	4000 kW gain with water injection
46	Backpressure	Base	$ -	$ 63,320	$ 63,320	466 kW loss with SCR
47	Catalyst Replacement	Base	$ -	$ 48,661	$ 48,661	
48	Increased Fuel Consumption	Base	$ 136,649	$ -	$ 136,649	236 Btu/kWh higher heat rate with water injection
49	Annual Distribution Check	Base	$ -	$ 55,000	$ 55,000	
50	**Total Direct Costs**	Base	$ (254,648)	$ 430,501	$ 175,852	
51						
52	**Indirect Annual Costs**					
53	Overhead	Base	$ 7,800	$ 42,000	$ 49,800	60 % of O&M
54	Administrative Charges	Base	$ 14,140	$ 93,000	$ 107,140	2 % of Installed Cost
55	Property Taxes	Base	$ -	$ -	$ -	Not Applicable to FMPA
56	Insurance	Base	$ 7,070	$ 46,000	$ 53,070	1 % of Installed Costs
57	Capital Recovery	Base	$ 77,560	$ 474,000	$ 551,560	
58	Total Indirect Annual Costs	Base	$ 106,570	$ 655,000	$ 761,570	
59						
60	**Total Annualized Cost**	Base	$ (148,078)	$ 1,085,501	$ 937,423	
61						
62	**Annual Tons NOx Produced**	620.2	87.1	87.1	87.1	
63						
64	**Annual Tons NOx Not Produced or Removed**	0.0	533.1	76.8	609.8	
65						
66	**Annual Tons NOx Emitted**	620.2	87.1	10.4	10.4	
67						
68	**Cost Effectiveness, $/ton**	Not Applicable	$ (278)	$ 14,143	$ 1,537	

Notes:
1. Based on 2,500 hours of year full load operation with 2.8 year catalyst life (7,000 operating hours).

Florida Municipal Power Agency

Roger A. Fo
General Manager and C

VIA E-MAIL
ORIGINAL VIA OVERNIGHT DELIVERY

February 18, 2005

Robert F. Anderson
General Manager, North American Sales
GE Packaged Power, Inc.
1333 West Loop South, Suite 1000
Houston, Texas 77027

RE: Contract for Fabrication and Construction of one LM6000 PC Sprint Combustion Turbine Based Simple Cycle Power Plant

Pursuant to our recent and ongoing discussions regarding the response of GE Packaged Power, Inc. (GE ENERGY) to the Florida Municipal Power Agency (FMPA) (FMPA and GE ENERGY are each referred to herein as a "Party" or collectively as the "Parties") All-Requirements Project Stock Island Combustion Turbine Unit 4 Combustion Turbine Generator Request for Quotations (the RFQ), we propose the following binding written contract (this Contract):

WHEREAS, FMPA has issued the RFQ and GE ENERGY has submitted a timely Gas Turbine Generator Commercial Proposal in response ~~to~~ the RFQ; and

WHEREAS, FMPA has evaluated all responses to the RFQ and now, pursuant to the terms hereof, desires to enter into this binding written contract to purchase one LM6000 PC Sprint combustion turbine based simple cycle generating set nominally rated at FORTY-FIVE (45) megawatts (MW) (the CT); and

WHEREAS, GE ENERGY desires to be contractually bound to fabricate and construct the CT and sell the CT to FMPA; and

WHEREAS, FMPA desires to be contractually bound to purchase the CT from GE ENERGY.

STATEMENT OF AGREEMENT

NOW, THEREFORE, in view of the foregoing premises and for and in consideration of the mutual benefits, covenants, and agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties, for themselves, their successors, and assigns, hereby agree as follows:

1. **RECITALS.** The above recitals are true and correct and are hereby incorporated into and made a material part of this Contract.

2. **CONSTRUCTION OF CT.** In consideration of a firm lump sum price of FOURTEEN MILLION TWO HUNDRED FORTY-THREE THOUSAND NINE DOLLARS ($14,243,009) to be paid by FMPA, GE ENERGY agrees to fabricate and construct one LM6000 PC Sprint combustion turbine based simple cycle generating set nominally rated at FORTY-FIVE (45) MW to fire fuel oil only to be located at Stock Island, Key West, Florida, in accordance with technical specifications and commercial terms and conditions mutually agreeable to the Parties.

3. **CANCELLATION.** If this Contract is canceled by either FMPA or GE after this date, for any reason, then the Party canceling this Contract shall pay to the other Party a cancellation fee in the amount of ONE HUNDRED THOUSAND DOLLARS ($100,000). Payment by the canceling Party of the foregoing cancellation fee shall be canceling Party's sole and exclusive liability and non-canceling Party's sole and exclusive remedy for cancellation of this Contract.

4. **EFFECTIVE DATE.** This Contract shall become effective as of the date last signed by a Party hereto.

5. **SEVERABILITY.** Wherever possible, each provision of this Contract shall be interpreted in such a manner as to be effective and valid under applicable law. Should any portion of this Contract be declared invalid for any reason, such declaration shall have no effect upon the remaining portions of this Contract. In the event any provision of this Contract is held by any tribunal of competent jurisdiction to be contrary to applicable law, the remaining provisions of this Contract shall remain in full force and effect.

6. **COUNTERPARTS.** This Contract may be executed in any number of counterparts, and signature pages exchanged by facsimile, and each counterpart shall be regarded for all purposes as an original, and such counterparts shall constitute, but one and the same instrument, it being understood that both Parties need not sign the same counterpart. The signature page of any counterpart, and facsimiles and photocopies thereof, may be appended to any other counterpart and when so appended shall constitute an original. In the event that any signature is delivered by facsimile transmission or by facsimile signature, such signature shall create a valid and binding obligation of the party executing (or on whose behalf such signature is executed) the Contract with the same force and effect as if such facsimile signature page were an original thereof.

Two originals of this Contract have been provided to you. If GE ENERGY agrees with and accepts this Contract please indicate such by dating and signing in the space provided below on both originals and return both originals to the undersigned, whereupon a fully executed original will be returned to you for your records.

Very truly yours,

FLORIDA MUNICIPAL POWER AGENCY

Roger A. Fontes
General Manager & CEO

Agreed to and Accepted By:

GE PACKAGED POWER, INC.

By: ______________________

Richard L. Kasson
(Print Name of Signatory)

Its: CFO

Date: 2/18/05

Cc: Stanley Armbruster, B&V
Fred Bryant, FMPA
Rick Casey, FMPA
Warren Ferguson, GE ENERGY
Jody Finklea, FMPA
Kevin Fleming, FMPA
Jim Hay, FMPA
Angela Morrison, HG&S
Russell Thompson, GE ENERGY

Department of
Environmental Protection

Northwest District
160 Governmental Center
Pensacola, Florida 32502

Jeb Bush
Governor

Colleen Castille
Secretary

April 12, 2005

BY ELECTRONIC MAIL
jovick@southernco.com

Mr. James O. Vick
Gulf Power Company
One Energy Place
Pensacola, Florida 32520

Dear Mr. Vick:

The purpose of this letter is to bring closure to the investigation associated with Warning Letter 033-1589 regarding an incident with the Crist Unit 4 Electrostatic Precipitator (ESP). Damages by Hurricane Ivan had not been previously identified and contributed to the ESP's performance failure on December 15, 2004.

The Continuous Emission Monitor (CEM) was mistakenly interpreted as a monitor malfunction and the opacity averaged 6% above the permit limit of 40 % opacity for approximately 62 six-minute periods. The incident was self-reported, the unit was taken off line, the problem was corrected, and your March 10, 2005 correspondence commits to spending approximately $10,000 to upgrade the CEM control panel and operator training to prevent such an incident from occurring again.

The Department appreciates Gulf Power's environmental commitment. The summary of the capital projects since 1990 that have reduced NOx and particulate is commendable. The CEM upgrade and operator training on the new control panel as well as the training on the compliance assurance monitoring requirements is expected to increase operator awareness. The increased awareness and more attention to details will result in lower emissions.

The Department would like to verify the CEM control panel upgrade and operator training as soon as practical and no later than during the next annual inspection.

If you have questions, please contact Andy Allen at 595-8364, extension 1223 or andy.allen@dep.state.fl.us.

Sincerely,

Sandra F. Veazey

Sandra F. Veazey
Air Program Administrator
sandra.veazey@dep.state.fl.us

SFV:aac
cc: G. Dwain Waters, QEP, Gulf Power Company (gdwaters@southernco.com)

Prevention of Significant Deterioration Air Permit Application Amendment for Stock Island Power Plant Combustion Turbine Unit 4

Submitted by

Florida Municipal Power Agency
and
Keys Energy Services

Prepared by
Black & Veatch

April 2005
Project No. 136839

Contents

Tables

Figures

1.0 Introduction

The Florida Municipal Power Agency (FMPA) and Utility Board of the City of Key West d/b/a Keys Energy Services (hereinafter referred to as KEYS) are implementing the installation of a GE LM6000 PC SPRINT combustion turbine in simple cycle operation (Project) at the KEYS Stock Island Power Plant site near Key West, Florida. KEYS owns the Stock Island site and will operate the unit. The proposed Project will be comprised of one simple cycle combustion turbine (SCCT) rated at a nominal 48 megawatts (MW) at ISO conditions and 100 percent load, firing No. 2 fuel oil (Combustion Turbine Unit 4). A prevention of significant deterioration (PSD) air construction permit application for the Project was submitted to the Florida Department of Environmental Protection (FDEP) on October 20, 2004. This submittal is an application amendment to the October 20, 2004 application.

Per this application amendment, FMPA/KEYS are requesting a limit of 2,500 hours per year operation on Combustion Turbine Unit 4. This application amendment includes information associated with taking the voluntary 2,500 hours per year limit. Based on discussions with FDEP personnel, with a limit of 2,500 hours per year of operation, BACT for Combustion Turbine Unit 4 is the use of water injection to achieve 42 ppmvd NO_x emissions corrected to 15 percent oxygen. This voluntary operating limit also results in a change in the Project potential to emit and the prevention of significant deterioration (PSD) applicability for some pollutants. These changes are discussed in this document.

In addition to the voluntary limit on operating hours, this application amendment reflects some minor changes to the site arrangement. A revised site arrangement is included in Appendix A. Revisions to the site arrangement include an updated arrangement for Combustion Turbine Unit 4 based on information obtained from GE and a change in the height and diameter of the new fuel oil storage tank along with a shift in the location of the fuel oil storage tank. While the site arrangement changes were relatively minor, the air dispersion modeling was redone to verify that the changes did not cause an exceedance of the Class II significant impact levels (SILs) or of any Class I air quality related values (AQRVs). The additional Class II modeling also includes modeling runs encompassing operation at 35 and 20 percent load conditions. By this submittal, the ambient air quality impact analysis encompasses operation of Combustion Turbine Unit 4 at loads ranging from 20 percent to 100 percent. The results of these additional modeling analyses are included in this application amendment.

This application amendment includes pages of the application forms that have been revised due to the aforementioned changes, along with the appropriate application form signature pages. These revised application forms pages are meant to replace the corresponding pages from the PSD air permit application submitted to the Department on October 20, 2004.

2.0 Project Characterization

The October 20, 2004 application gave a detailed description of the Project. This section includes a summary of the estimated emissions and a discussion of New Source Review (NSR) PSD applicability based on 2,500 hours per year operation for Combustion Turbine Unit 4.

2.1 Project Emissions

This section discusses the potential to emit (PTE) of all regulated PSD air pollutants resulting from the Project. Performance data for Combustion Turbine Unit 4, based on vendor data from GE at loads of 35 and 20 percent, distillate fuel firing, and ambient air temperatures of 41° F, 59° F, 78° F, and 95° F are provided in Appendix B. Similar performance data information for design loads of 50, 75 and 100 percent was included in the October 20, 2004 application.

The maximum pound per hour emission rates (rounded to the nearest pound) considering all ambient temperatures are presented in Table 2-1. The NO_x emission rate shown in Table 2-1 is based on using water injection to achieve 42 ppmv NO_x emissions corrected to 15 percent O_2.

Table 2-1
Project Maximum Emission Rates (lb/h)*

Pollutant	Emission Rate (lb/h)
NO_x	76
SO_2	24
CO	17
PM/PM_{10}	25
VOC	5
SAM	5.4

*Maximum pound per hour emission rates (rounded to the nearest pound) for Combustion Turbine Unit 4 considering site ambient temperatures and partial load operation.

2.2 Maximum Project Potential to Emit

The proposed operating scenario for Combustion Turbine Unit 4 includes a maximum of 2,500 hours per year of operation. At this operating rate, NO_x emissions are equal to 94.9 tons per year (assumes operation for 2,500 hours and 41° F emission rates). Combustion Turbine Unit 4 will operate between 20 and 100 percent of full load. The Project's potential to emit for each pollutant is summarized in Table 2-2. The NO_x emission rate shown in Table 2-2 is based on using water injection to achieve 42 ppmv NO_x emissions corrected to 15 percent O_2. The emission rates given in Table 2-2 are based on Combustion Turbine Unit 4 operating 2,500 hours per year, conservatively assuming the worst case hourly emission rate occurs for each pollutant for the entire operating period. The applicable PSD significant emission levels for each pollutant are included for reference purposes in the table, and a spreadsheet used to calculate the potential to emit is included as Appendix C.

2.3 Prevention of Significant Deterioration Applicability

As discussed in the October 20, 2004 submittal, the existing facility is an existing major stationary source under PSD regulations. Based on the voluntary limit of 2,500 hours per year operation for Combustion Turbine Unit 4, the estimated emissions of NO_x and PM/PM_{10} resulting from the proposed Project exceed the PSD significant emissions levels of 40 and 25/15 tpy, respectively. Therefore, the Project's emissions of NO_x, PM, and PM_{10} are subject to PSD review as a major modification to an existing major source. By taking a limit of 2,500 hours per year operation, the Project is no longer subject to PSD review for SO_2 and sulfuric acid mist. Based on this PSD applicability, only NO_x and PM_{10} are included in the additional Class II modeling analysis presented in this application amendment.

Table 2-2
PSD Applicability

Pollutant	Project PTE (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NO_x	94.9[a]	40	**yes**
SO_2	29.5[a,b]	40	**no**
CO	20.6[a]	100	no
PM/PM_{10}	31.3[a,c]	25/15	**yes**
VOC	6.9[a,d]	40	no
Sulfuric Acid Mist	6.8[a,e]	7	**no**
Total Reduced Sulfur	negl.	10	no
Hydrogen Sulfide	negl.	10	no
Vinyl Chloride	negl.	1	no
Total Fluorides	negl.	3	no
Mercury	0.001[f]	0.1	no
Lead	0.007[f]	0.6	no

[a]Based on 2,500 hours full load operation per year for all pollutants, conservatively assuming the worst case hourly emission rate (those at 100 percent load and 41° F) for each pollutant for the entire operating period.
[b]Based on 0.05 percent sulfur distillate fuel oil and assuming 100 percent conversion to SO_2.
[c]Assumes front and back half PM/PM_{10} emissions.
[d]VOC PTE is based on potential emissions from the Project's combustion source and emissions from the fuel oil storage tank.
[e]Assumes a 15 percent conversion of SO_2 to SO_3 and 100 percent conversion of SO_3 to H_2SO_4.
[f]Based on AP-42 emission factors.
Note: PTE calculations are provided in a spreadsheet included in Appendix C.

3.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the PSD air quality impact analysis for those pollutants which will have a PTE greater than the PSD significant emission rate (NO_x and PM/PM_{10}). A detailed description of the air quality impact analysis methodology and basis was included in the October 20, 2004 application. This discussion is limited to presenting the results of the modeling using the revised site arrangement and encompassing operation at loads ranging from 20 to 100 percent of full load. Figure 3-1 illustrates the nested rectangular grid, fence line receptors, and the relative location of the emission source and downwash structures under the revised site arrangement.

3.1 Model Input Source Parameters

The ISCST3 model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads and ambient temperatures. For this analysis, "enveloping" was not used. Each set of operating conditions was used to perform a separate modeling run. Performance data for the combustion turbine operating at 20 and 35 percent loads over a range of ambient temperatures (41, 59, 78, and 95° F) is included in Appendix B. Similar performance data for operation at 50, 75 and 100 percent loads was included in the October 20, 2004 application. The corresponding stack parameters and emission rates for each load and ambient temperature considered in the analysis are presented in Table 3-1.

3.2 Model Results

As presented in Section 2, the Project's PTE exceeds the PSD significant emission thresholds for NO_x and PM/PM_{10}. In accordance with the previously approved modeling protocol, ISCST3 air dispersion modeling was performed for NO_x and PM/PM_{10} for each applicable averaging period. Table 3-2 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels (SILs) and the pre-construction monitoring requirements. The values in Table 3-2 represent the maximum model predicted concentration over the associated ambient temperature range for each load. As Table 3-2 indicates, the Project's maximum model-predicted concentrations are less than the PSD Class II SILs for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and AAQS analyses) are required.

Additionally, the maximum predicted concentrations are less than the pre-construction

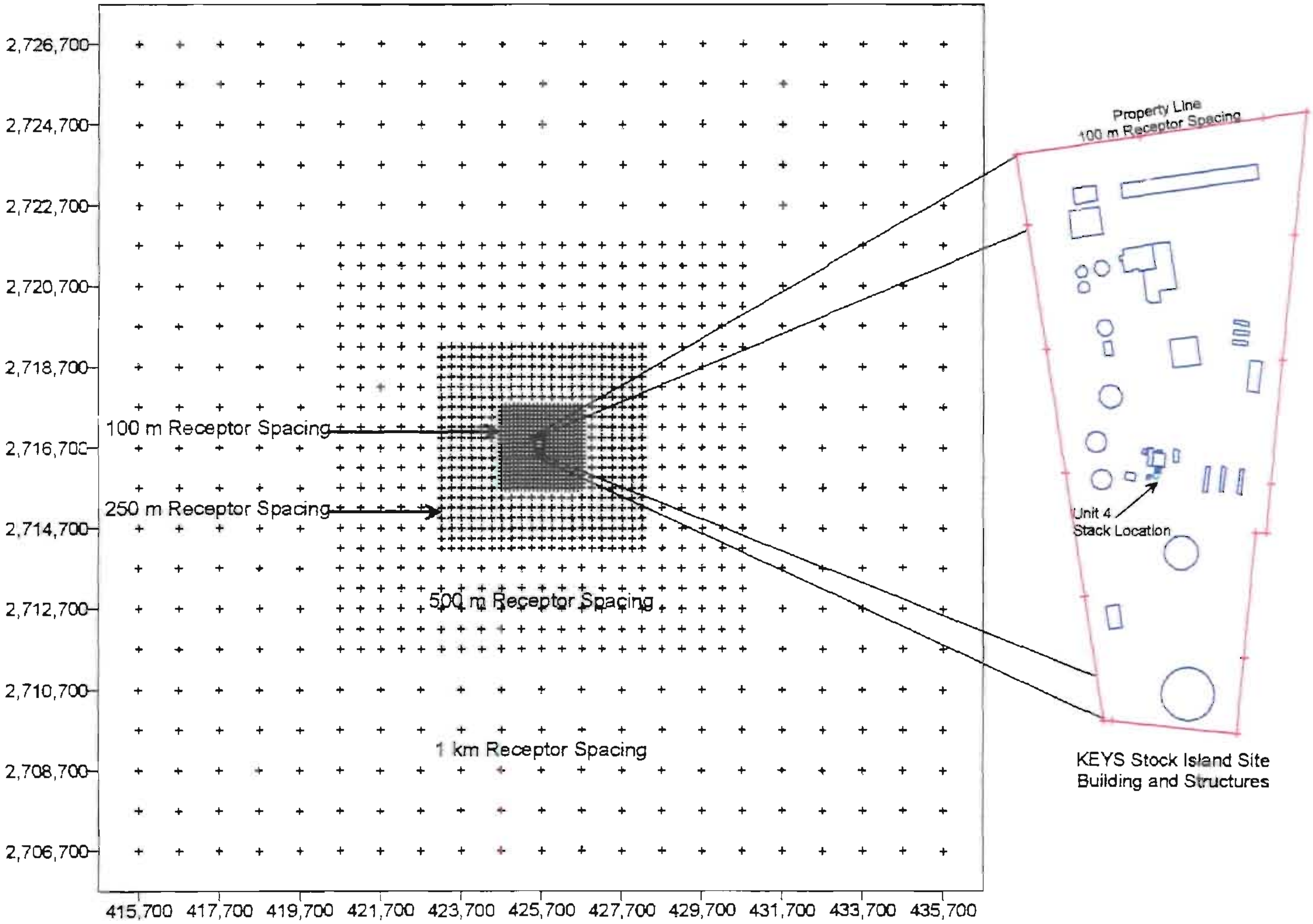


Figure 3-1
ISCST3 Class II Modeling Receptors

Table 3-1
Stack Parameters and Pollutant Emissions
Used in ISCST3 Modeling Analysis [a]

Load	Ambient Temperature (°F)	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)	
						NO_x	PM/PM_{10}[(b)]
100	95	18.29	3.05	34.75	730.93	8.15	3.15
	78	18.29	3.05	36.58	720.37	8.78	3.15
	59	18.29	3.05	38.10	712.04	9.29	3.15
	41	18.29	3.05	38.71	707.59	9.56	3.15
75	95	18.29	3.05	29.57	729.26	6.40	3.15
	78	18.29	3.05	31.39	713.15	6.87	3.15
	59	18.29	3.05	32.61	693.71	7.28	3.15
	41	18.29	3.05	32.92	678.15	7.45	3.15
50	95	18.29	3.05	24.08	722.04	4.84	3.15
	78	18.29	3.05	25.30	710.93	5.15	3.15
	59	18.29	3.05	25.91	697.59	5.42	3.15
	41	18.29	3.05	26.21	679.26	5.53	3.15
35	95	18.29	3.05	20.88	699.82	3.88	2.39
	78	18.29	3.05	21.64	686.48	4.09	2.39
	59	18.29	3.05	22.10	672.04	4.28	2.39
	41	18.29	3.05	22.40	654.26	4.37	2.39
20	95	18.29	3.05	17.68	677.04	2.92	1.76
	78	18.29	3.05	17.98	661.48	3.04	1.76
	59	18.29	3.05	18.29	646.48	3.15	1.76
	41	18.29	3.05	18.59	628.71	3.21	1.76

[a] Stack parameter and emission information obtained from an in-house computer application provided and approved by GE for estimating such data. PM/PM_{10} emissions at 35 and 20 percent load are based on results of the air dispersion modeling and engineering judgment.

[b] PM/PM_{10} represents both front and back half emissions.

Table 3-2
ISCST3 Model-Predicted Class II Impacts

Load	Pollutant – Averaging Period	Model-Predicted Impact [a,d] ($\mu g/m^3$)	PSD Class II SIL [b] ($\mu g/m^3$)	Exceed SIL?	De Minimis Monitoring Level [c] ($\mu g/m^3$)	Pre-construction Monitoring Required?
100	NO_x – Annual	0.14	1	NO	14	NO
	PM_{10} – Annual	0.05	1	NO	---	NO
	PM_{10} – 24 hour	2.93	5	NO	10	NO
75	NO_x – Annual	0.14	1	NO	14	NO
	PM_{10} – Annual	0.06	1	NO	---	NO
	PM_{10} – 24 hour	3.64	5	NO	10	NO
50	NO_x – Annual	0.14	1	NO	14	NO
	PM_{10} – Annual	0.08	1	NO	---	NO
	PM_{10} – 24 hour	4.92	5	NO	10	NO
35	NO_x – Annual	0.14	1	NO	14	NO
	PM_{10} – Annual	0.08	1	NO	---	NO
	PM_{10} – 24 hour	4.74	5	NO	10	NO
20	NO_x – Annual	0.20	1	NO	14	NO
	PM_{10} – Annual	0.12	1	NO	---	NO
	PM_{10} – 24 hour	4.79	5	NO	10	NO

[a] Impacts represent the highest first high model-predicted concentration from all five year of meteorological data modeled and the maximum concentration over the range of ambient temperatures (95, 78, 59, and 41°F).

[b] Predicted impacts that are below the specified level indicate that the proposed project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.

[c] This criteria is used to determine if pre-construction ambient air monitoring is required to assess current and future compliance with Ambient Air Quality Standards.

[d] Annual impacts were conservatively determined assuming 8,760 hours per year operation.

monitoring de minimis levels for each pollutant and applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD pre-construction monitoring requirements.

4.0 Additional Impact Analyses

The following sections present the results of additional analyses conducted based on the revised site arrangement. As discussed in Section 2, because a voluntary operational limit of 2,500 hours per year is being accepted, the Project is no longer subject to PSD review for SO_2. Therefore, additional impact analyses pertaining to SO_2 emissions were not conducted for this application amendment, although SO_2 emissions are included in the Class I Regional Haze and Deposition analyses. The projected impacts on commercial, residential, and industrial growth remains the same as presented in the October 20, 2004 application. The projected impacts on vegetation and soils remains the same as presented in the October 20, 2004 application.

4.1 Class I Area Impact Analysis

As part of the air impact evaluation for the Project, analyses of the Project's effect on the Everglades National Park (ENP) were performed. The ENP is a PSD Class I area located in southern Florida, approximately 90 km northeast of the Project site. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this analysis are regional haze and deposition. Additionally, Class I Significant Impact Levels (SILs) were evaluated and compared to the recommended thresholds.

The methodology used in the CALPUFF analysis is the same as that described in the October 20, 2004 application. Also, please see the October 20, 2004 application for a detailed discussion of the meteorological and geophysical databases used in the analysis, the preparation of those databases for introduction into the modeling system, and the air modeling approach to assess impacts at ENP.

4.1.1 Project Emissions

The maximum pound per hour emission rates at 100 percent load and the worst case stack parameters at 100 percent load (i.e. minimum exit velocity and minimum exit temperature) were used for the pollutants modeled with CALPUFF. Those pollutants include NO_x, SO_2, and PM_{10}. Table 3-1 contains the stack parameters and emission rates modeled in CALPUFF.

4.1.2 CALPUFF Analyses

The model inputs and settings for the CALPUFF modeling system were used to complete the Class I analyses on the ENP, including regional haze, deposition, and Class I SILs.

4.1.2.1 Regional Haze Analysis. A regional haze analysis was performed for the ENP for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations. Please see the October 20, 2004 application for a detailed discussion of the basis for the regional haze analysis.

Based on the predicted SO_4, NO_3, and PM_{10} concentrations, the proposed Project's emissions were compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5. As illustrated in Table 4-1, the regional haze results are less than the 5 percent change in extinction threshold and, as such, no further analysis is necessary.

Table 4-1
Regional Haze Results[a]

Modeled Year	Change in Extinction[b] (%)	Recommended Threshold (%)
1990	0.27	5
1992	0.68	5
1996	0.61	5

[a]The results represent a relative humidity cap value of 95 percent. Additionally, the relative humidity was capped at 98 percent for informational purposes only. The results indicated no exceedances of the recommended 5 percent threshold over all 3 years modeled with the largest value being only 0.97 percent.
[b]Change in extinction was compared against the natural conditions presented in the FLAG 2000 document.

4.1.2.2 Deposition Analyses. Deposition analyses, using the same methodology as detailed in the October 20, 2004 application, were performed for ENP for both total sulfur and total nitrogen.

The model-predicted results were compared to the 0.01 kg/ha/year Deposition Analysis Threshold (DAT) developed jointly by the NPS and the U.S. Fish and Wildlife Service (FWS). Table 4-2 presents the results of the deposition analysis for each of the 3 modeling years. As illustrated in the table, the deposition results are less than the 0.01 DAT and, as such, no further analysis is necessary. Also, as seen in this table there was no change in the deposition results as compared to the results presented in the October 20, 2004 application.

Table 4-2
Deposition Results

Modeled Year	Total Nitrogen Deposition[a,d] (kg/ha/yr)	Total Sulfur Deposition[b,d] (kg/ha/yr)	Deposition Analysis Threshold[c]
1990	0.0004	0.0004	0.01
1992	0.0005	0.0005	0.01
1996	0.0007	0.0008	0.01

[a]Includes both wet and dry deposition with SO_4, NO_x, HNO_3, and NO_3 contributing to the nitrogen mass.
[b]Includes both wet and dry deposition with SO_2 and SO_4 contributing sulfur mass.
[c]For all areas east of the Mississippi River.
[d]Annual impacts were conservatively determined assuming 8,760 hours per year operation.

4.1.2.3 Class I Impact Analysis. Ground-level impacts (in µg/m3) at the ENP were calculated for NO_x and PM_{10} criteria pollutants for each applicable averaging period. The results of this analysis were compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values. Table 4-3 presents the results of the Class I analysis for each of the 3 modeling years. As illustrated in the table, there are no impacts above the Class I SILs and, as such, no further analysis is necessary. Also, as seen in this table there was no change in the modeled impacts as compared to the results presented in the October 20, 2004 application. Also, as previously noted, because SO_2 is no longer subject to PSD review, modeling of SO_2 impacts was not conducted.

Table 4-3
Class I Significant Impact Level (SIL) Modeling Results

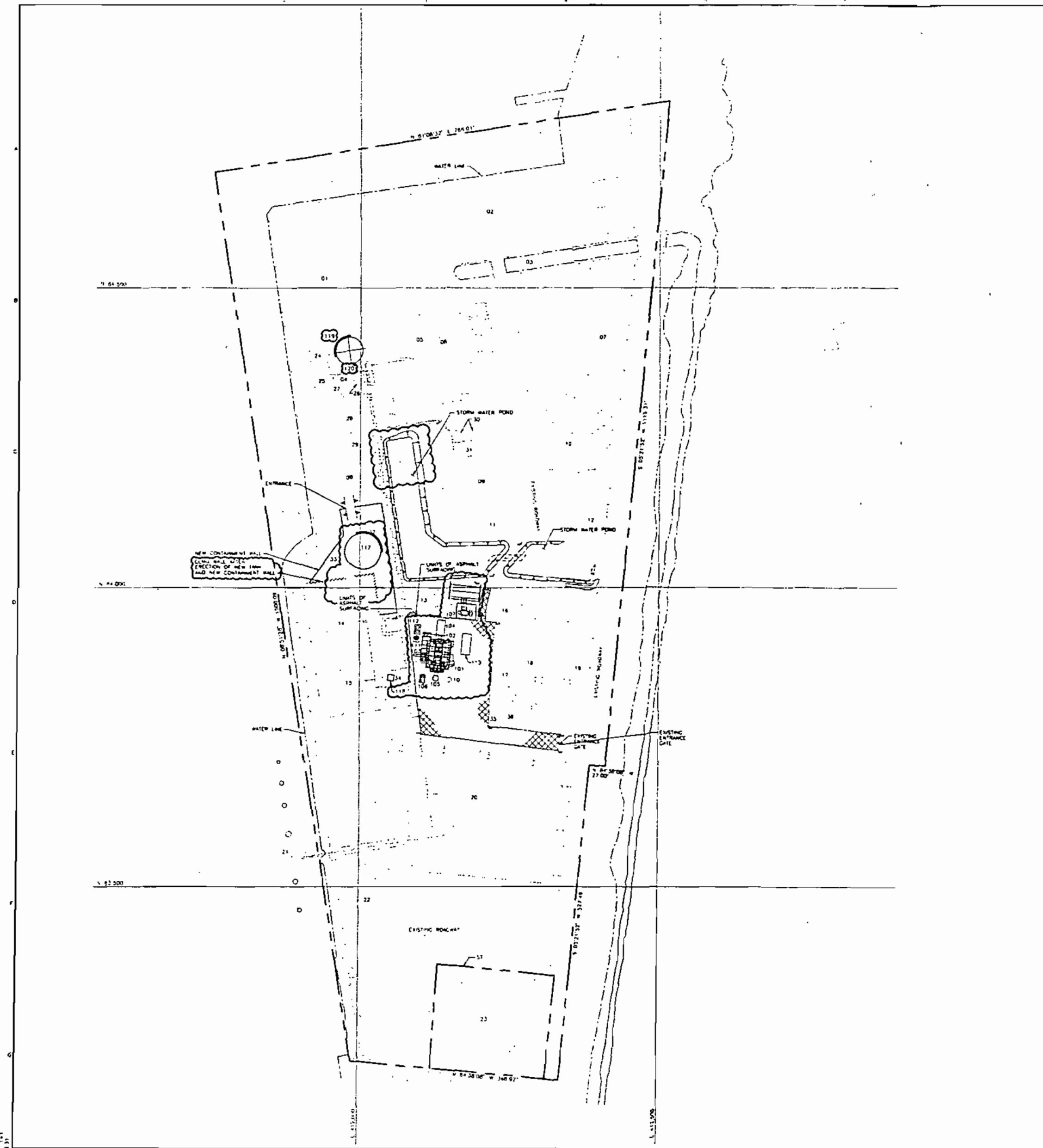
Modeled Year	Pollutant and Averaging Period	Modeled Impact ($\mu g/m^3$)*	Significant Impact Level** ($\mu g/m^3$)	Exceed SIL?
1990	NO_x – Annual	0.0004	0.10	NO
	PM_{10} – Annual	0.0003	0.16	NO
	PM_{10} – 24-hour	0.018	0.32	NO
1992	NO_x – Annual	0.0003	0.10	NO
	PM_{10} – Annual	0.0004	0.16	NO
	PM_{10} – 24-hour	0.015	0.32	NO
1996	NO_x – Annual	0.0005	0.10	NO
	PM_{10} – Annual	0.0004	0.16	NO
	PM_{10} – 24-hour	0.024	0.32	NO

*Annual impacts were conservatively determined assuming 8,760 hours per year operation.
**Class I Significant Impact Levels are calculated as 4 percent of the PSD Class I Increment values.

Appendix A
Site Arrangement

Appendix B
20 and 35 Percent Load Turbine Data

Best Available Copy



EXISTING FACILITIES LEGEND					
ID	FACILITY	FOUNDATION	TIEDOWN LOCATION NORTH	EAST	REMARKS
01	WAREHOUSE	-	-	-	
02	WAREHOUSE	-	-	-	
03	CIRCULATING WATER DISCHARGE FLUME	-	-	-	
04	RETIRED STEAM UNIT STACK	-	-	-	
05	RETIRED STEAM UNIT	-	-	-	
06	SYNCHRONOUS CONDENSER	-	-	-	
07	STOCK ISLAND SUBSTATION	-	-	-	
08	FIRE PUMP HOUSE	-	-	-	
09	MEDIUM SPEED DIESEL GENERATOR BUILDING	-	-	-	
10	HIGH SPEED DIESELS	-	-	-	
11	VEHICLE MAINTENANCE LIFT	-	-	-	
12	MAINTENANCE GARAGE	-	-	-	
13	STORAGE AREA	-	-	-	TO BE RELOCATED
14	DIESEL FUEL TANK (500,000 GALLONS, 32' HIGH)	-	-	-	
15	DIESEL FUEL TANK (500,000 GALLONS, 32' HIGH)	-	-	-	
16	SWITCHYARD	-	-	-	
17	COMBUSTION TURBINE GENERATOR #1	-	-	-	
18	COMBUSTION TURBINE GENERATOR #2	-	-	-	
19	COMBUSTION TURBINE GENERATOR #3	-	-	-	
20	DIESEL FUEL TANK (1.8 MILLION GALLONS, 40' HIGH)	-	-	-	
21	FUEL LOADING DOCK	-	-	-	
22	TWO-STORY OFFICE BUILDING	-	-	-	
23	FOAM WATER TANK	-	-	-	
24	DEMINERALIZED WATER TANK (169,000 GALLONS, 32' HIGH)	-	-	-	
25	DEMINERALIZED WATER TANK (189,000 GALLONS, 32' HIGH)	-	-	-	
26	CEMS BUILDING FOR RETIRED STEAM UNIT	-	-	-	
27	CINGULAR CEL TOWER CONTROL BUILDING	-	-	-	
28	ABANDONED TANK STORAGE SHED	-	-	-	
29	SERVICE/FIRE WATER TANK (300,000 GALLONS, 40' HIGH)	-	-	-	
30	FUEL OIL DAY TANKS	-	-	-	
31	LUBE OIL STORAGE TANK	-	-	-	
32	STORAGE SHEDS	-	-	-	TO BE RELOCATED
33	FIRE HYDRANT	-	-	-	TO BE RELOCATED
34	FUEL OIL FORWARDING BUILDING	-	-	-	
35	STORAGE BUILDING	-	-	-	
36	WATER INJECTION SKID	-	-	-	
37	FLORIDA KEYS AQUADUCT AUTHORITY PROPERTY LINE	-	-	-	

NEW FACILITIES LEGEND					
ID	FACILITY	FOUNDATION	TIEDOWN LOCATION NORTH	EAST	REMARKS
101	COMBUSTION TURBINE (CT)	-	-	-	
102	COMBUSTION TURBINE GENERATOR	-	-	-	
103	COMBUSTION TURBINE AUXILIARY SKID	-	-	-	
104	GENERATOR ROTOR REMOVAL AREA	-	-	-	
105	STACK	-	-	-	
106	CONTINUOUS EMISSIONS MONITORS (CEMS)	-	-	-	
107	GENERATOR STEP-UP TRANSFORMER	-	-	-	
108	GENERATOR CIRCUIT BREAKER (LOCATED IN AUX ELEC MOD - SEE ITEM 113)	-	-	-	
109	UNIT AUXILIARY TRANSFORMER (LOCATED IN AUX ELEC MOD - SEE ITEM 113)	-	-	-	
110	WATER WASH SUMP	-	-	-	
111	FIN FAN COOLER	-	-	-	
112	AIR COMPRESSOR SKID	-	-	-	
113	AUXILIARY ELECTRICAL EQUIPMENT MODULE	-	-	-	
114	480V DISTRIBUTION SWITCHGEAR (LOCATED IN AUX ELECT MOD - SEE ITEM 113)	-	-	-	
115	NOT USED	-	-	-	
116	NOT USED	-	-	-	
117	DIESEL FUEL OIL TANK (1 MILLION GALLONS, 48' HIGH)	-	-	-	
118	FUEL OIL FORWARDING SKID	-	-	-	
119	DEMINERALIZED WATER STORAGE TANK (350,000 GALLONS, 32' HIGH)	-	-	-	
120	DEMINERALIZED WATER PUMP SKID	-	-	-	

GENERAL LEGEND

PROPERTY BOUNDARY

EXISTING FENCE

EXISTING OVERHEAD TRANSMISSION LINES

WATER LINE

NEW FENCE

EXISTING CONTAINMENT WALL TO BE DEMOLISHED

ASPHALT SURFACING

GRAVEL SURFACING

NOTES

1. THIS SPECIAL PURPOSE SURVEY WAS PERFORMED TO ESTABLISH SITE CONTROL MONUMENTS WITH AERIAL TARGETING FOR USE IN PHOTOGRAMMETRIC MAPPING OF THE SITE. THE BOUNDARY LINES WITH BEARINGS AND LENGTHS DEPICTED HEREON WERE PLOTTED FROM INFORMATION PROVIDED BY THE CLIENT. THE BOUNDARY LOCATION IS APPROXIMATE, AS GRAPHICALLY SCALED FROM DRAWINGS PROVIDED BY THE CLIENT AND SHOULD NOT BE RELIED UPON FOR BOUNDARY SURVEY DETERMINATION.
2. VERTICAL CONTROL IS BASED ON THE NORTH AMERICAN VERTICAL DATUM OF 1988 (NAVD 88). ELEVATIONS ARE EXPRESSED IN FEET, AND DECIMALS THEREOF. TO CONVERT ELEVATIONS FOR THE STOCK ISLAND AREA FROM NAVD 88 TO THE NGVD 29 DATUM USE THE FOLLOWING CONVERSION:
NAVD 88 + 1.34' = NGVD 29
3. HORIZONTAL CONTROL DATA IS BASED ON FLORIDA STATE PLANE COORDINATE SYSTEM (EAST ZONE), NORTH AMERICAN DATUM OF 1983 (NAD 83) WITH THE 1999 ADJUSTMENT. COORDINATE VALUES ARE EXPRESSED AS "GRID COORDINATES" AND ARE IN FEET, AND DECIMALS THEREOF. FOR CONVERSION FROM GRID TO GROUND VALUES USE A SITE SCALE FACTOR OF 1.00000943

PRELIMINARY
NOT TO BE USED
FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE
1	03/28/05	GENERAL REVISIONS
0	10/01/04	ISSUED FOR BIDS

SCALE: 1" = 60'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA
SIGNED ______
DATE ______ REG. NO. ______

BLACK & VEATCH CORPORATION

STOCK ISLAND
COMBUSTION TURBINE UNIT 4

SITE ARRANGEMENT
GE LM6000 UNIT

PROJECT / DRAWING NUMBER: 136839-DS-S1001
REV: 1

4/8/2005
FMPA
Stock Island-Key West
Black & Veatch Project 136839.004
LM6000 Emissions Estimates, Revision 0, 35% & 20% Load Cases

Case Number	17	13	18	14	19	15	20	16
CTG Model	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	35%	20%	35%	20%	35%	20%	35%	20%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	59	59	78	78	95	95
Ambient Conditions								
Ambient Temperature, F	41.0	41.0	59.0	59.0	78.0	78.0	95.0	95.0
Ambient Relative Humidity, %	100.0	100.0	60.0	60.0	81.8	81.8	60.2	60.2
Atmospheric Pressure, psia	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696
Combustion Turbine Performance								
CTG Performance Reference	GE	GE	GE	GE	GE	GE	GE	GE
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	41.0	41.0	59.0	59.0	78.0	78.0	95.0	95.0
CTG Compr. Inlet Relative Humidity, %	100.0	100.0	60.2	60.2	81.8	81.8	60.3	60.3
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
CTG Load Level (percent of Base Load)	35%	20%	35%	20%	35%	20%	35%	20%
Gross CTG Output, kW	17,446	9,969	16,789	9,592	15,647	8,940	14,244	8,139
Gross CTG Heat Rate, Btu/kWh (LHV)	11,369	14,604	11,573	14,901	11,868	15,406	12,367	16,283
Gross CTG Heat Rate, Btu/kWh (HHV)	12,109	15,553	12,327	15,870	12,642	16,407	13,167	17,341
CTG Heat Input, MBtu/h (LHV)	198.4	145.6	194.3	142.9	165.7	137.7	176.2	132.5
CTG Heat Input, MBtu/h (HHV)	211.3	155.1	207.0	152.2	197.8	146.7	187.6	141.1
CTG Water/Steam Injection Flow, lb/h	8,314	5,426	8,312	5,428	7,182	4,688	6,504	4,312
Injection Fluid/Fuel Ratio	0.8	0.7	0.8	0.7	0.7	0.6	0.7	0.6
CTG Exhaust Flow, lb/h	690,117	600,637	661,828	576,891	630,615	551,561	599,071	526,962
CTG Exhaust Temperature, F	718	672	750	704	776	731	800	759
Combustion Turbine Fuel								
Total CTG Fuel Flow, lb/h	10,780	7,910	10,565	7,770	10,095	7,490	9,570	7,200
CTG Fuel Temperature, F	80	80	80	80	80	80	80	80
CTG Fuel LHV, Btu/lb	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400
CTG Fuel HHV, Btu/lb	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596
HHV/LHV Ratio	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650
CTG Fuel Composition (Ultimate Analysis by Weight)								
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
H2	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%
N2	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

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CTG Model	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	35%	20%	35%	20%	35%	20%	35%	20%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	59	59	78	78	95	95
Stack Emissions								
Stack Exhaust Analysis - Volume Basis - Wet								
Ar	0.94%	0.94%	0.94%	0.94%	0.93%	0.93%	0.92%	0.92%
CO2	3.11%	2.67%	3.18%	2.73%	3.17%	2.74%	3.16%	2.75%
H2O	5.93%	5.06%	6.22%	5.33%	7.62%	6.78%	8.21%	7.43%
N2	74.67%	75.17%	74.47%	74.98%	73.38%	73.85%	72.91%	73.35%
O2	15.37%	16.16%	15.21%	16.02%	14.92%	15.70%	14.81%	15.55%
SO2 (after SO2 oxidation)	0.000579%	0.000499%	0.000595%	0.000510%	0.000590%	0.000510%	0.000590%	0.000510%
SO3 (after SO2 oxidation)	0.000105%	0.000090%	0.000105%	0.000090%	0.000105%	0.000090%	0.000105%	0.000090%
Total	100.00%	100.0%	100.00%	100.0%	100.00%	100.0%	100.00%	100.0%
Stack Exit Temperature, F	718	672	750	704	776	731	800	759
Stack Diameter, ft (estimated)	10	10	10	10	10	10	10	10
Stack Flow, lb/h	690,113	600,634	661,824	576,888	630,611	551,558	599,067	526,959
Stack Flow, scfm	152,381	132,340	146,244	127,204	140,128	122,355	133,417	117,161
Stack Flow, acfm	346,848	288,306	342,252	284,984	334,638	280,377	324,565	274,723
Stack Exit Velocity, ft/s	73.5	61.0	72.5	60.0	71.0	59.0	68.5	58.0
Stack NOx Emissions								
NOx, ppmvd (dry, 15% O2)	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
NOx, ppmvd (dry)	32.8	27.9	33.5	28.5	34.0	29.1	34.1	29.4
NOx, ppmvw (wet)	30.7	26.4	31.4	27.0	31.4	27.1	31.3	27.2
NOx, lb/h as NO2	34.7	25.5	34.0	25.0	32.5	24.1	30.8	23.2
NOx, lb/MBtu (LHV) as NO2	0.1750	0.1749	0.1751	0.1750	0.1750	0.1751	0.1749	0.1749
NOx, lb/MBtu (HHV) as NO2	0.1643	0.1643	0.1644	0.1643	0.1644	0.1644	0.1643	0.1642
Stack CO Emissions								
CO, ppmvd (dry, 15% O2)	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
CO, ppmvd (dry)	11.7	9.9	12.0	10.2	12.2	10.4	12.2	10.5
CO, ppmvw (wet)	11.0	9.4	11.3	9.7	11.2	9.7	11.2	9.7
CO, lb/h	7.6	5.5	7.4	5.4	7.1	5.2	6.7	5.0
CO, lb/MBtu (LHV)	0.0381	0.0380	0.0381	0.0381	0.0381	0.0381	0.0380	0.0380
CO, lb/MBtu (HHV)	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357
Stack SO2 Emissions, after SO2 Oxidation								
SO2, ppmvd (dry, 15% O2)	7.96	7.96	7.96	7.96	7.96	7.96	7.96	7.96
SO2, ppmvd (dry)	6.20	5.28	6.35	5.41	6.43	5.50	6.46	5.57
SO2, ppmvw (wet)	5.82	5.00	5.95	5.12	5.94	5.13	5.92	5.15
SO2, lb/h	9.16	6.72	8.98	6.60	8.58	6.37	8.13	6.12
SO2, lb/MBtu (LHV)	0.0462	0.0462	0.0462	0.0462	0.0462	0.0462	0.0462	0.0462
SO2, lb/MBtu (HHV)	0.0434	0.0433	0.0434	0.0434	0.0434	0.0434	0.0434	0.0434

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CTG Model	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	35%	20%	35%	20%	35%	20%	35%	20%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	59	59	78	78	95	95
Stack Emissions - continued								
Stack UHC Emissions								
UHC, ppmvd (dry, 15% O2)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
UHC, ppmvd	7.8	6.6	8.0	6.8	8.1	6.9	8.1	7.0
UHC, ppmvw	7.3	6.3	7.5	6.4	7.5	6.5	7.5	6.5
UHC, lb/h as CH4	2.9	2.1	2.9	2.1	2.7	2.0	2.6	1.9
UHC, lb/MBtu (LHV)	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145
UHC, lb/MBtu (HHV)	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136
Stack VOC Emissions								
VOC, ppmvd (dry, 15% O2)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
VOC, ppmvd (dry)	6.3	5.3	6.4	5.4	6.5	5.5	6.5	5.6
VOC, ppmvw (wet)	5.9	5.0	6.0	5.1	6.0	5.2	6.0	5.2
VOC, lb/h as CH4	2.3	1.7	2.3	1.7	2.2	1.6	2.1	1.5
VOC, lb/MBtu (LHV)	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116
VOC, lb/MBtu (HHV)	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109
PM10 without the Effects of SO2 oxidation								
PM10 Emissions - Front Half Catch Only								
PM10, lb/h	10.6	7.8	10.6	7.8	10.6	7.8	10.6	7.8
PM10, lb/MBtu (LHV)	0.0533	0.0535	0.0544	0.0545	0.0569	0.0565	0.0600	0.0587
PM10, lb/MBtu (HHV)	0.0500	0.0502	0.0510	0.0511	0.0534	0.0531	0.0563	0.0552
PM10 Emissions - Front and Back Half Catch								
PM10, lb/h	19.0	14.0	19.0	14.0	19.0	14.0	19.0	14.0
PM10, lb/MBtu (LHV)	0.0958	0.0962	0.0978	0.0980	0.1023	0.1017	0.1079	0.1057
PM10, lb/MBtu (HHV)	0.0899	0.0903	0.0918	0.0920	0.0961	0.0954	0.1013	0.0992
Total Effects of SO2 Oxidation								
Total SO2 to SO3 conversion rate, %vol	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Total Amount of SO2 converted to SO3, lb/h	1.62	1.19	1.58	1.17	1.51	1.12	1.44	1.08
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	2.48	1.82	2.43	1.78	2.32	1.72	2.20	1.65

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N_2 and 20.99% O_2
3. Standard conditions are defined as 60 F, 14.696 psia, Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH_4 calibration gas.
5. The CTG performance is from a General Electric estimation program.

Appendix C
Emission Calculation Spreadsheet

Stock Island Combustion Turbine No. 4
Potential to emit analysis
LM6000 data
Prepared by: Black & Veatch

Potential to Emit based on 2,500 hours per year operation.

Pollutant	Maximum Hourly Emission Rate (lb/hour)	Potential to Emit[c] (tpy)	PSD SEL (tpy)	PSD Major Modification (Yes/No)
NO_x	75.9	94.9	40	Yes
CO	16.5	20.6	100	No
PM (front half)	13.9	17.4	25	No
PM_{10} (front half)	13.9	17.4	15	Yes
PM (front and back half)	25.0	31.3	25	Yes
PM_{10} (front and back half)	25.0	31.3	15	Yes
SO_2[a]	23.6	29.5	40	No
VOC	5.0	6.3	40	No
H_2SO_4 mist[b]	5.4	6.8	7	No

[a] SO_2 emissions do not include effect of oxidation to SO_3.

[b] H_2SO_4 based on assumption that 15.0% by volume SO_2 is converted to SO_3 and 100% of SO_3 is converted to H_2SO_4.

[c] Based on 2,500 hours full load operation per year for all pollutants, conservatively assuming the worst case hourly emission rate occurs for each pollutant for the entire operating period.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : Daniel Cassel – Director of Generation
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: The Utility Board of the City of Key West dba Keys Energy Services Street Address: 1001 James Street City: Key West State: FL Zip Code: 33041-6100
3.	Owner/Authorized Representative Telephone Numbers... Telephone: (305) 295-1142 ext. Fax: (305) 295-1145
4.	Owner/Authorized Representative Email Address: Dan.Cassel@KeysEnergy.com
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* Daniel Cassel 4/12/05 Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Stanley A. Armbruster, P.E.
   Registration Number: 30562

2. Professional Engineer Mailing Address...
   Organization/Firm: Black & Veatch
   Street Address: 11401 Lamar Avenue
   City: Overland Park State: KS Zip Code: 66211

3. Professional Engineer Telephone Numbers...
   Telephone: (913) 458-2763 ext. Fax: (913) 458-2934

4. Professional Engineer Email Address: ArmbrusterSA@bv.com

5. Professional Engineer Statement:

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

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

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

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

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

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

Signature Date: April 13, 2005

(seal)

STANLEY A. ARMBRUSTER
LICENSE
30562
STATE OF FLORIDA
PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1.	Maximum Process or Throughput Rate: 8.358 million gallons per year fuel oil
2.	Maximum Production Rate:
3.	Maximum Heat Input Rate: 462.0 million Btu/hr (HHV)
4.	Maximum Incineration Rate: pounds/hr tons/day
5.	Requested Maximum Operating Schedule: 24 hours/day 7 days/week 52 weeks/year 2,500 hours/year
6.	Operating Capacity/Schedule Comment: The maximum annual hours of operation of 2,500 hours per year shown in Field 5 is requested based on negotiations with FDEP. The maximum annual fuel oil use rate shown in Field 1 is equivalent to the unit operating at full load firing 2,500 hours per year, at an ambient temperature of 41 F. The unit will be operated between 20 and 100 percent of full load. The maximum heat input rate shown in Field 3 is with operation at 100% load at the site minimum ambient temperature of 41°F. Note that the heat input rate is a function of ambient temperature. As discussed in FDEP Guidance Document DARM-OGG-07, higher CT inlet temperatures will result in a lower heat input rate (MMBtu/hr) and vice versa. Variations of heat input (capacity) are to be expected due to the range of ambient temperatures and humidities encountered at the site. When they become available, the CT operating curves (capacity vs. inlet air temperature) will be provided to the Department. It is requested that the permit for this unit include Conditions 1 and 2 of DARM-OGG-07. We request inclusion of the standard permitting note that the heat input rates are provided for informational purposes only and are not intended to be enforceable limits.

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Combustion Turbine No. 4	2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: V	6. Stack Height: 60 feet	7. Exit Diameter: 10 feet
8. Exit Temperature: 837°F	9. Actual Volumetric Flow Rate: 566,400 acfm	10. Water Vapor: 11%

11. Maximum Dry Standard Flow Rate: 227,000 dscfm	12. Nonstack Emission Point Height: 60 feet
13. Emission Point UTM Coordinates... Zone: East (km): 425.6418 North (km): 2716.6800	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: Emission point information given in Fields 8 through 11 are based on operation at 100% load and an ambient temperature of 78°F. This information will vary depending on ambient temperature and load.	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): No. 2 fuel oil used in the combustion turbine		
2. Source Classification Code (SCC): 20100101	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 3.34	5. Maximum Annual Rate: 8.358	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.05	8. Maximum % Ash:	9. Million Btu per SCC Unit: 138 (HHV)
10. Segment Comment: The maximum fuel input to the combustion turbine is a function of the ambient temperature. The maximum hourly rate give in Field 4 is based on operation at 100% load at the site minimum ambient temperature of 41°F. The maximum annual fuel oil use rate of 8.358 million gallons per year given in Field 5 is based on the unit operating at full load firing 2,500 hours per year, at an ambient temperature of 41 F.		

Segment Description and Rate: Segment __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

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

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 16.5 lb/hour 20.6 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly potential emissions are based on operation at conditions resulting in the maximum hourly rate. These conditions are at 100% load and an ambient temperature of 41°F. The maximum hourly CO emission rate is 16.5 lb/hour. The maximum annual CO emissions are based on operation of the unit at 100% load at the minimum ambient temperature at the site for 2,500 hours per year. Annual emissions = 16.5 lb/hr x 2,500 hours/year x 1 ton/2,000 lb = 20.6 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on a CO emission rate of 15 ppmv, dry at 15% O_2.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 75.9 lb/hour 94.9 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly potential emissions are based on operation at conditions resulting in the maximum hourly rate. These conditions are at 100% load and an ambient temperature of 41°F. The maximum hourly NO_x emission rate is 75.9 lb/hour. The maximum annual NO_x emissions are based on firing 13.567 million gallons per year of fuel oil, which is equivalent to operation of the unit at 100% load at the minimum ambient temperature at the site for 2,500 hours per year. Annual emissions = 75.9 lb/hr x 2,500 hours/year x 1 ton/2,000 lbs = 94.9 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on a NO_x emission rate of 42 ppmv, dry at 15% O_2.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0075 x (14.4/Y) + F in percent by volume at 15% oxygen and on a dry basis	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions are from 40 CFR 60, Subpart GG and Rule 62-204.800(8)(b).39 - 40 CFR 60, Subpart GG Stationary Gas Turbines, adopted by reference. See Attachment M for a more detailed discussion of compliance with Subpart GG, AS REVISED JULY 8, 2004.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 42 ppm by volume at 15% oxygen and on a dry basis	4. Equivalent Allowable Emissions: 75.9 lb/hour 94.9 tons/year
5. Method of Compliance: CEMS.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 41°F and the equivalent annual allowable emissions rate is based on operation at 100% load at the minimum ambient temperature at the site of 41°F for 2,500 hours per year.	

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 25 lb/hour 31.3 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 25 lb/hr Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly potential PM emissions are estimated to be 25 lb/hour.
The maximum annual PM emissions are based on operation for 2,500 hours per year.
Annual emissions = 25 lb/hr x 2,500 hours/year x 1 ton/2,000 lbs = 31.3 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on a PM emission rate (front and back half catch) of 25 lb/hour.

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 25 lb/hour 31.3 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 25 lb/hr Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly potential PM_{10} emissions are estimated to be 25 lb/. The maximum annual PM_{10} emissions are based on operation for 2,500 hours per year. Annual emissions = 25 lb/hr x 2,500 hours/year x 1 ton/2,000 lbs = 31.3 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on a PM_{10} emission rate (front and back half catch) of 25 lb/hour.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 23.55 lb/hour 29.4 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data using low sulfur fuel oil (0.05% sulfur). The maximum hourly potential emissions are based on operation at 100% load and an ambient temperature of 41°F. The maximum hourly SO_2 emission rate is 23.55 lb/hour. The maximum annual SO_2 emissions are based on operation of the unit at 100% load for 2,500 hours per year.
Annual emissions = 23.55 lb/hr x 2,500 hours/year x 1 ton/2,000 lbs = 29.4 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on using low sulfur fuel oil (0.05% sulfur) and conservatively assume all sulfur in the fuel is converted to SO_2 and there is no oxidation of SO_2 to SO_3.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.8% sulfur by weight in the fuel	4. Equivalent Allowable Emissions: 377 lb/hour 471 tons/year
5. Method of Compliance: Fuel testing and monitoring will be conducted in accordance with 40 CFR 60 Subpart GG, AS REVISED JULY 8, 2004.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions are from 40 CFR 60, Subpart GG and Rule 62-204.800(8)(b).39 - 40 CFR 60, Subpart GG Stationary Gas Turbines, adopted by reference. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 41°F and the equivalent allowable annual emissions rate is based operation at 100% load for 2,500 hours per year.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.05% sulfur by weight in the fuel	4. Equivalent Allowable Emissions: 23.55 lb/hour 29.4 tons/year
5. Method of Compliance: Fuel testing and monitoring will be conducted in accordance with 40 CFR 60 Subpart GG, AS REVISED JULY 8, 2004.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is requested by this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 41°F and the equivalent allowable annual emissions rate is based on operation at 100% load for 2,500 hours per year.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 5.0 lb/hour 6.3 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly potential emissions are based on operation at 100% load and an ambient temperature of 41°F. The maximum hourly VOC emission rate is 5.0 lb/hour. The maximum annual VOC emissions are based on operation of the unit at 100% load for 2,500 hours per year. Annual emissions = 5.0 lb/hr x 2,500 hours/year x 1 ton/2,000 lbs = 6.3 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on a VOC emission rate of 8.0 ppmv, dry at 15% O_2.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: SAM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 5.41 lb/hour 6.8 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:

Potential emissions are based on vendor data.

The maximum hourly potential emissions are based on operation at 100% load and an ambient temperature of 41°F. The maximum hourly sulfuric acid mist emission rate is 5.41 lb/hour.

The maximum annual sulfuric acid mist emissions are based on operation of the unit at 100% load for 2,500 hours per year.

Annual emissions = 5.41 lb/hr x 2,500 hours/year x 1 ton/2,000 lbs = 6.8 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Potential emissions shown in Fields 3 and 8 are based on use of low sulfur fuel oil (0.05% sulfur) and an SO_2 oxidation rate of 15% conversion of SO_2 to SO_3 and an assumed 100% conversion of SO_3 to H_2SO_4.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.05% sulfur by weight in the fuel	4. Equivalent Allowable Emissions: 5.41 lb/hour 6.8 tons/year
5. Method of Compliance: Fuel testing and monitoring.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is requested by this application. Equivalent allowable emission rates are based on 15% oxidation of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4 and are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 41°F and the equivalent allowable annual emissions rate is based on operation at 100% load for 2,500 hours per year.	

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

Adams, Patty

From: Mulkey, Cindy
Sent: Wednesday, June 15, 2005 11:34 AM
To: Adams, Patty
Subject: FW: extension request

Cindy Mulkey
Engineering Specialist
Bureau of Air Regulation
Permitting South
(850) 921-8968
FAX (850)921-9533
SC 291-8968

From: Carter, Kathy
Sent: Tuesday, June 14, 2005 10:28 AM
To: Mulkey, Cindy; Gibson, Victoria; Chisolm, Jack
Cc: Light, Lisa
Subject: extension request

Hello all:

OGC received a request for extension of time from Keys Energy Services, ARMS Permit No. 0870003-007-AC. They are requesting to and includng 8/15/05.

Kathy

Office of General Counsel
Agency Clerk
245-2212
Kathy.Carter@dep.state.fl.us

(305) 295-1000
1001 James Street
PO Box 6100
Key West, FL 33041-6100
www.KeysEnergy.com

UTILITY BOARD OF THE CITY OF KEY WEST

June 17, 2005

Al Linero, Program Administrator, South Permitting
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
2600 Blair Stone Road MS 5500
Tallahassee, FL 32399-2400

RECEIVED
JUN 20 2005
BUREAU OF AIR REGULATION

Subject: Keys Energy Services Stock Island Power Plant
Combustion Turbine Unit 4 – GE LM6000 SPRINT
File No. 0870003-007-AC (PSD-FL-348)

Dear Mr. Linero:

Keys Energy Services (KEYS) respectfully submits the enclosed comments regarding the Department's proposed PSD permit.

If you have any questions, please contact Edward Garcia of KEYS at (305) 295-1134 or Susan Schumann of FMPA at (407) 355-7767.

Sincerely,
Keys Energy Services

Dan Cassel

Dan Cassel
Director of Generation

Enclosures

cc:
C. Jansen, KEYS
L. Tejeda, KEYS
E. Garcia, KEYS
S. Schumann, FMPA

Explanation of proposed revisions submitted by FMPA/KEYS

Revision number	Corresponding page number in draft permit	Explanation of revision
1	2	Based on a contract between GE and FMPA, dated February 18, 2005, the combustion turbine specified in this permit is not subject to Proposed Subpart KKKK
2	5	Clarification of Department's determination and correction for the date of the proposed regulation
3	6	Clarification of language regarding future installation of SCR system
4	7	This permitting note is an editorial comment unrelated to this permit
5	12	Clarification of referenced specific condition
6	14	Clarification of language regarding future installation of SCR system
7	14	Clarification of Department's determination and correction for the date of the proposed regulation
8	15	Edit
9	16	Clarification of temperature
10	18	Edit
11	21	Clarification of referenced specific condition

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

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BUREAU OF AIR REGULATION

4APT-ATMB

Mr. Michael Cooke
Director
Division of Air Resource Management
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Cooke:

We have received a request from Mr. A.A. Linero for a determination regarding the applicability of New Source Performance Standards (NSPS) Subpart KKKK -"Standards of Performance for Stationary Combustion Turbines." NSPS Subpart KKKK was proposed in the Federal Register on February 18, 2005, and the final standard will apply to affected facilities which commence construction, modification, or reconstruction after that date of proposal. The determination request relates to whether Subpart KKKK will apply to a 45 megawatt (MW) simple cycle combustion turbine purchased by the Florida Municipal Power Agency (FMPA). As discussed below, additional information will be needed for us to determine if the combustion turbine will be subject to Subpart KKKK.

The State has provided to us a February 18, 2005, contract between FMPA and GE Packaged Power, Inc. for the fabrication and construction of a 45 MW fuel oil-fired LM6000 PC Sprint combustion turbine-based simple cycle generating set by GE Packaged Power, Inc. The combustion turbine is to be located at Stock Island Power Plant in Key West, Florida. Included in the contract is the purchase price of the combustion turbine and a cancellation fee which must be paid if the contract is broken by either party after the date of the contract.

NSPS Subpart KKKK applies to "... a stationary combustion turbine with a power output at peak load equal to or greater than 1 megawatt (MW), which commences construction, modification, or reconstruction after February 18, 2005 ..." (Emphasis added) 40 CFR Section 60.4305. The NSPS general provisions (Subpart A) define "commenced" to mean:

> ... with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of

construction or modification. (Emphasis added) 40 CFR Section 60.2.

Therefore, a stationary combustion turbine that "commenced" construction after February 18, 2005, would be considered a "new" facility subject to the requirements of Subpart KKKK. A stationary combustion turbine that "commenced" construction on or prior to February 18, 2005, would be considered an "existing" facility and would not be subject to the requirements of Subpart KKKK.

Based on our review of the February 18, 2005, contract provided by FMPA, we are not able to determine whether construction of the combustion turbine "commenced" on that date. The contract provided by FMPA contains no commitment to complete a continuous program of construction within a reasonable time, as required by the NSPS regulations. If any obligations regarding the scheduling of construction were made on or prior to February 18, 2005, FMPA will need to provide documentation of those commitments for our consideration. Without adequate documentation that the February 18, 2005, contract between FMPA and GE Packaged Power will result in a continuous program of construction, the combustion turbine in question would be a "new" facility subject to NSPS Subpart KKKK.

This determination has been provided with assistance from the Environmental Protection Agency's Office of Enforcement and Compliance Assurance (OECA). If there are any questions regarding this letter, please contact Mr. Keith Goff of the EPA Region 4 staff at (404) 562-9137.

Sincerely,

Jim Bartlett for

Beverly H. Banister
Director
Air, Pesticides and Toxics
Management Division

cc: Mr. A. A. Linero,
Florida Department of Environmental Protection

Mr. Greg Fried, OECA

=== COVER PAGE ===

TO: ____________________

FROM: OGC

FAX: 2452303

TEL: 2452242

COMMENT:

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OFFICE OF GENERAL COUNSEL

3900 Commonwealth Boulevard, M.S. 35
Marjory Stoneman Douglas Building
Tallahassee, Florida 32399-3000

FACSIMILE TRANSMITTAL

To:	Vickie Gibson
Fax:	921-9533
From:	Lea Crandall
Phone:	245-2212
Fax:	(850) 245-2301
Pages:	4 Pages Including Cover Date: August 15, 2005
RE:	Request for Enlargement of Time – 0870003-007-AC Keys Energy Services

Comments:

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☐ Overnight Delivery

Original will NOT follow ☒

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

OGC No.: 05-1508
ARMS Permit No.: 0870003-007-AC
PSD Permit No. PSD-FL-348

Keys Energy Services
Stock Island Combustion Turbine 4
Monroe County, Florida
_______________________________________/

REQUEST FOR ENLARGEMENT OF TIME

By and through undersigned counsel, Keys Energy Services (KEYS) hereby requests, pursuant to Florida Administrative Code Rule 62-110.106(4), an enlargement of time, to and including September 30, 2005, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, KEYS states the following:

1. On or about June 2, 2005, KEYS received from the Department of Environmental Protection ("Department") an "Intent to Issue Air Construction Permit" and the accompanying "Draft Permit," (Draft Permit No. PSD-FL-348), for the Stock Island Combustion Turbine 4, to be located in Monroe County, Florida.

2. Based on KEYS' initial review, the Draft Permit and associated documents contain several provisions that may warrant clarification or corrections or further discussions with the Department's Bureau of Air Regulation permitting staff.

3. KEYS is now trying to resolve questions raised by the Department and the U.S. Environmental Protection Agency.

4. The Department granted KEYS' first Request for Enlargement of Time, allowing

until August 15, 2005, to file a petition in this matter.

5. KEYS is now requesting until September 30, 2005, in order to resolve remaining issues.

6. This request is filed simply as a protective measure to avoid waiver of KEYS' right to challenge certain conditions contained in the Draft Title V Permit. Grant of this request will not prejudice either party, but will further their mutual interest and hopefully avoid the need to file a Petition and proceed to a formal administrative hearing.

WHEREFORE, Keys Energy Services respectfully requests that the time for KEYS to file a Petition for Administrative Proceedings in regard to the Department's Intent to Issue Air Construction Permit No. PSD-FL-348 be formally extended to and including September 30, 2005. If the Department denies this Request, KEYS respectfully requests an opportunity to file a Petition for Administrative Proceeding within 10 days of such denial.

RESPECTFULLY SUBMITTED this 15th day of August, 2005.

By: Robert A. Manning

Robert A. Manning
Florida Bar ID No. 0035173
Hopping Green & Sams, P.A.
123 South Calhoun Street
Post Office Box 6526
Tallahassee, Florida 32314
(850) 222-7500
(850) 224-8551 Facsimile

Attorneys for KEYS ENERGY SERVICES

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by Hand Delivery to Kathy Carter, Agency Clerk, and Doug Beason, General Counsel, Florida Department of Environmental Protection, 3900 Commonwealth Boulevard, Suite 300, Tallahassee, Florida 32399-3000; and Trina Vielhauer, Florida Department of Environmental Protection, Division of Air Resource Management, 111 S. Magnolia Drive, Suite 23, Tallahassee, Florida 32399 this 15th day of August, 2005.

Robert A. Manning

Florida Municipal Power Agency

Frederick M. Bryant
General Counsel

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BUREAU OF AIR REGULATION

August 18, 2005

Beverly Banister
Director Air, Pesticides, and Toxics Management Division
United States Environmental Protection Agency, Region 4
Atlanta Federal Center
61 Forsyth Street
Atlanta, GA 30303-8960

Michael Cooke
Director Division of Air Resources Management
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: FMPA/KEYS Stock Island Power Plant

Dear Ms. Banister and Mr. Cooke:

The following information is provided in response to EPA's letter dated August 1, 2005, regarding the applicability of NSPS Subpart KKKK to a project at the Florida Municipal Power Agency / Keys Energy Services (FMPA/ KEYS) Stock Island generating facility: the addition of a 48 MW (nominal) simple-cycle combustion turbine, GE LM6000 PC (Stock Island Unit). This is in addition to the information forwarded (via e-mail) to Keith Goff and Doug Neeley on July 26 and 29, 2005, respectively, which apparently was not received prior to sending the August 1 letter.

In its August 1, 2005 letter, EPA stated that it could not determine, based solely on the contract between FMPA and GE dated February 18, 2005, whether the Stock Island Unit is subject to the newly enacted NSPS Subpart KKKK. Specifically, EPA states that the contract does not contain a commitment "to complete a continuous program of construction," as required by 40 CFR 60.2. EPA identified no other issues regarding whether FMPA "commenced

P.O. Box 3209 | Tallahassee, FL 32315-3209
2061 - 2 Delta Way | Tallahassee, FL 32303
T. (850) 297-2011 | Toll Free (877) 297-2012
F. (850) 297-2014 | www.fmpa.com

construction" by the proposal date, and FMPA/KEYS understands that providing evidence of its commitment to a continuous program of construction will resolve this issue.

FMPA's February 18, 2005 contract solidified years of previous planning on the Stock Island Unit, and represented a commitment to complete a continuous program of construction within a reasonable time, as required by the NSPS regulations. Specifically, the following information/documents highlight the evidence of this commitment, continually from 1997 to

today, to provide the needed generation by June 2006 (other documents/information are referenced in the attached, more detailed list. Copies of all documents are attached.):

- In 1997, FMPA entered a contract with the City of Key West's Utility Board to provide 60% on-island power generation to the Florida Keys.
- In May, 2003, steps were already being initiated to assure additional power generation would be in service on Keys Energy Services' system by summer 2006.
- In November 21, 2003 a Contract/Business Plan was entered into between FMPA and consultants Black & Veatch (B&V) that identifies the tasks that need to be completed to install the combustion turbine at the Keys Energy Services Stock Island facility, the parties responsible for completing these tasks, and an estimate of the cost or effort to complete the tasks.
- Between December 16 -18, 2003 FMPA held numerous meetings and site visits to plan for installation of the Stock Island Unit.
- As early as April 12, 2004, FMPA staff made a recommendation that the General Electric (GE) LM 6000 Sprint combustion turbine be installed at Stock Island.
- On July 17, 2004, FMPA met with members of the Florida Department of Environmental Protection (FDEP) to discuss preliminary matters for air permitting of the new combustion unit.
- On July 21, 2004, FMPA issued a Request for Proposal to provide the Combustion Turbine Generator for the Stock Island Project.
- On July 27, 2004, the FMPA Board approved funding for the Stock Island Combustion Turbine Unit #4.
- On October 19, 2004, FMPA submitted a PSD Permit application to FDEP.
- From November, 2004 through February 18, 2005, negotiation meetings were held between FMPA and GE to discuss the specifics of the combustion turbine to be purchased.
- On February 18, 2005, GE and FMPA entered into a binding contract, subjecting FMPA to $100,000 cancellation penalty, for construction of the combustion turbine at Stock Island.
- On June 2, 2005, FDEP issued a draft construction permit, concluding that the Stock Island Unit #4 "commenced construction" before Subpart KKKK's proposal date, and therefore was not subject to that regulation.

- GE began constructing the Combustion Turbine in April, 2005, and has steadily progressed since that time.
- At present, the Combustion Unit has already entered into testing that is expected to be complete by September 1, 2005.

As this information demonstrates, FMPA has been contractually bound to provide 60% on-island generation to the Keys Energy Services for eight years. On or before February 18, 2005, FMPA steadily progressed to ready the site, prepare for the necessary construction permits, and to solicit and acquire a contract for construction of the combustion turbine to be placed at Keys Energy Services' Stock Island facility. On February 18, 2005, FMPA entered into a binding contract with GE for construction of the Combustion Turbine that would be placed on the site. Since that time, work on the site and Combustion Turbine has continued to progress to achieve on-island power generation by June 2006.

Clearly, FMPA/KEYS should not be subject to the NSPS regulations because it did not "commence construction" after February 18, 2005. Instead, FMPA has been on a continual path to provide the needed generation since as early as 1997 through the present day, and its February 18, 2005 contract is the culmination of this effort. In an effort to resolve this issue expeditiously, FMPA wishes to meet at EPA Region 4 in Atlanta to discuss these documents and any questions that may arise. We will contact you in the next few days to schedule this meeting.

Sincerely yours,

Frederick M. Bryant

Frederick M. Bryant
General Counsel
Florida Municipal Power Agency

Attachments

cc: Trina Vielhauer, FDEP
Al Linero, FDEP
Keith Goff, EPA
Greg Fried, OECA
Robert Manning, HGS

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

OGC Case No.: 05-1508
ARMS Permit No: 0870003-007-AC
PSD Permit No: PSD-FL-348

Keys Energy Services
Stock Island Combustion Turbine 4
Monroe County, Florida
_______________________________________/

NOTICE OF WITHDRAWAL OF ENLARGEMENT OF TIME

Keys Energy Services ("KEYS"), by and through undersigned counsel, hereby withdraws its Second Request for Enlargement of Time to file a petition for formal administrative proceedings in accordance with Chapter 120, Florida Statutes. KEYS currently has pending a Second Request for Enlargement of Time, which the Department granted until September 30, 2005, in response to the "Intent to Issue Air Construction Permit" and accompanying "Draft Permit"(Draft Permit No. PSD-FL-348) for the Stock Island Turbine 4, to be located in Monroe County, Florida, to negotiate certain changes in the Draft Permit with the Department. Following discussions with Department representatives, KEYS and the Department have come to agreement on the issues involved in the above referenced Draft Permit, and KEYS understands that the Department will promptly issue a Final Permit. Accordingly, conditioned upon the Department's issuance of the Final Permit in the manner agreed to between KEYS and the Department, KEYS hereby withdraws its Request for Enlargement of Time.

RESPECTFULLY SUBMITTED this 1st day of September, 2005

By: Robert A. Manning

Robert A. Manning
Florida Bar ID No. 0035173
Hopping Green & Sams, P.A.
123 South Calhoun Street
Post Office Box 6526
Tallahassee, Florida 32314
(850) 222-7500
(850) 224-8551 Facsimile

Attorneys for Keys Energy Services

229290.1

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by Hand Delivery to Kathy Carter, Agency Clerk, and Doug Beason, General Counsel, Florida Department of Environmental Protection, 3900 Commonwealth Boulevard, Suite 300, Tallahassee, Florida 32399-3000; and Trina Vielhauer, Florida Department of Environmental Protection, Division of Air Resource Management, 111 S. Magnolia Drive, Suite 23, Tallahassee, Florida 32399 this 1st day of September, 2005

Robert A. Manning

Robert A. Manning

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Mr. Daniel Cassel
Director of Generation
Keys ~~Energy Services~~
1001 ~~James Street~~
Key W5st~~, FL 33040~~-6100

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Name (Please Print Clearly) (To be completed by mailer)
Mr. Daniel Cassel, Keys Energy Services
Street, Apt. No.; or PO Box No.
1001 James St.
City, State, ZIP+ 4
Key West, FL 33401-6100

PS Form 3800, July 1999 See Reverse for Instructions

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1. Article Addressed to:

Mr. Daniel Cassel
Director of Generation
Keys Energy Services
1001 James St.
Key West, FL ~~33401-6100~~
33041-6100

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*) Chris Sands

B. Date of Delivery 11/19/0

C. Signature X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Recipient's Name *(Please Print Clearly) (to be completed by mailer)*
Mr. Daniel Cassel, Keys Energy Serv.
Street, Apt. No.; or PO Box No.
1001 James St.
City, State, ZIP+4
Key West, FL 33401-6100

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1. Article Addressed to:

Mr. Daniel Cassel
Director of Generation
Keys ~~Energy Services~~
1001 ~~James Street~~
Key W5st, FL 33040-6100

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☒ Agent
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D. Is delivery address different from item 1? ☒ Yes
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KeyWest FL
33041

3. Service Type
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4. Restricted Delivery? (*Extra Fee*) ☐ Yes

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Name (Please Print Clearly) (To be completed by mailer)
Mr. Daniel Cassel, Keys Energy Services
Street, Apt. No.; or PO Box No.
1001 James St.
City, State, ZIP+ 4
Key West, FL 33401-6100

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Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Recipient's Name *(Please Print Clearly) (to be completed by mailer)*
Mr. Daniel Cassel, Keys Energy Serv.
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1001 James St.
City, State, ZIP+4
Key West, FL 33401-6100

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1 Article Addressed to:

Mr. Daniel Cassel
Director of Generation
Keys Energy Services
1001 James St.
Key West, FL ~~33401-6100~~
33041-6100

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A. Received by *(Please Print Clearly)* Chris Sands
B. Date of Delivery 11/19/0

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X [signature]
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☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
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4. Restricted Delivery? *(Extra Fee)* ☐ Yes

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Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
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Tallahassee, FL 32399-2400

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1. Article Addressed to:

Mr. Frederick Bryant
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819

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A. Signature
X Rena Stewart ☒ Agent ☐ Addressee

B. Received by (*Printed Name*) RENA STEWART

C. Date of Delivery 6/6

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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Mr. Frederick Bryant
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819

PS Form 3800, January 2001 See Reverse for Instructions

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Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33041-6100

PS Form 3800, January 2001 — See Reverse for Instructions

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1. Article Addressed to:

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33041-6100

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X R. Mesa
☐ Agent
☐ Addressee

B. Received by (*Printed Name*) R. MESA

C. Date of Delivery 6-7-05

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

KEY WEST FL 33040
JUN -7 2005
USPS

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Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

32399+2400

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1. Article Addressed to:

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33041-6100

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X K. Mesa ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) K Mesa

C. Date of Delivery 9-16-05

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

USPS SEP 16 2005 KEY WEST FL 33040

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Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33041-6100

PS Form 3800, June 2002 See Reverse for Instructions

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Mr. Frederick Bryant
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819

PS Form 3800, June 2002 — See Reverse for Instructions

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1. Article Addressed to:

Mr. Frederick Bryant
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819

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FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

October 25, 2004

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
P. O. Box 25287
Denver, Colorado 80225

RE: Keys Energy Services
Stock Island Power Plant
0870003-007-AC, PSD-FL-348

Dear Mr. Bunyak:

Enclosed for your review and comment is a PSD application submitted by Keys Energy Services for a new combustion turbine at their Stock Island Power Plant in Monroe County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Cindy Mulkey, review engineer, at 850/921-8968.

Sincerely,

Patty Adams

for A. A. Linero, P.E.
Administrator
South Permitting Section

AAL/pa

Enclosure

cc: C. Mulkey

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

October 25, 2004

Mr. Gregg M. Worley, Chief
Air Permits Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303-8960

RE: Keys Energy Services
Stock Island Power Plant
0870003-007-AC, PSD-FL-348

Dear Mr. Worley:

Enclosed for your review and comment is a PSD application submitted by Keys Energy Services for a new combustion turbine at their Stock Island Power Plant in Monroe County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Cindy Mulkey, review engineer, at 850/921-8968.

Sincerely,

Patty Adams

for A. A. Linero, P.E.
Administrator
South Permitting Section

AAL/pa

Enclosure

cc: C. Mulkey

FLORIDA

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

February 17, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33401-6100

Re: Second Request for Additional Information
Combustion Turbine Unit 4 – GE LM6000 SPRINT
File No. 0870003-007-AC (PSD-FL-348)

Dear Mr. Cassel:

On January 18, 2005 the Department received the KEYS Energy response to our request for additional information dated November 10, 2004. On February 16 we received via electronic mail an update to that response based on our meeting with your representatives (and EPA by phone) on February 2. We have not yet reviewed that information.

Based on the response received on January 18, we require additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

Cost effectiveness should also be calculated based on the uncontrolled NO_X emissions prior to water injection. The starting value, for example, might be greater than 100 ppm. The calculation should include a credit for the additional power generated as a result of the increased mass flow when injecting water. This issue was discussed with your representatives at our meeting of February 2.

Attached is a fact sheet for 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines under development by EPA. We understand from our EPA Region 4 permitting contact that a rule will be proposed this month in the Federal Register.

NSPS rules provide a floor for BACT determinations. The draft of the rule proposes a limit of 1.2 lb NO_X/megawatt-hr for new oil-fired combustion turbines such as the one proposed by KEYS Energy. Based on the application, it appears that emissions from KEYS Energy Unit 4 will be greater than 1.5 lb NO_X/MWH. Both values are significantly greater than typical BACT determinations for continuous duty combustion turbines. We are not allowed to issue BACT determinations for a combustion turbine that are less than the corresponding NSPS.

We will forward any additional comments received from EPA Region 4.

At the meeting, we cited a number of assumptions and conclusions by KEYS Energy with which we do not agree and why we don't agree. It is not necessary to enumerate them at this time. We have limited this request for additional information to just a few issues.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1), F.A.C., "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department ... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions, please call me at 850/921-9523.

Sincerely,

A. A. Linero 2/17

A. A. Linero, Administrator
South Air Permitting Section

Cc: Ron Blackburn, DEP
Edward Garcia, Keys Energy Services
Stanley Armbruster, P.E., Black & Veatch
Susan Schumann, FMPA
Jim Little, EPA Region 4
John Bunyak, National Park Service

FACT SHEET

PROPOSED RULE SETTING THE STANDARDS OF PERFORMANCE FOR STATIONARY COMBUSTION TURBINES

ACTION

- On February 9, 2005, the Environmental Protection Agency (EPA) proposed a rule that would reduce emissions of air pollutants from new stationary combustion turbines. These proposed requirements would apply to new turbines with a peak rated power output greater than or equal to 1 megawatt (MW). These turbines are used at facilities such as power plants, pipeline compressor stations, and chemical and manufacturing plants.

- These proposed standards, known as New Source Performance Standards (NSPS), would apply to new turbines and reflect changes in nitrogen oxides (NO_x) emission control technologies and turbine design since the NSPS for stationary combustion turbines were originally promulgated in 1979.

- New, modified and reconstructed turbines would have to comply with the proposed rule. A new turbine is defined as one that commences construction after the date of proposal and would have to comply upon startup. Modified or reconstructed sources would have up to 6 months after the rule is final, or 6 months after startup, whichever is later, to demonstrate compliance with the new standards.

- The proposed rule would reduce emissions of NO_x and sulfur dioxide (SO_2).

- The proposed rule would require that new turbines meet the following emission limits for NO_x:
  - Natural gas-fired turbines below 30 MW meet an emission limit of 132 nanograms per Joule (ng/J) [1.0 pound per megawatt-hour (lb/MW-hr)].
  - Oil and other fuel-fired turbines below 30 MW meet an emission limit of 234 ng/J (1.9 lb/MW-hr).
  - Natural gas-fired turbines greater than or equal to 30 MW meet an emission limit of 50 ng/J (0.39 lb/MW-hr).
  - Oil and other fuel-fired turbines greater than or equal to 30 MW meet an emission limit of 146 ng/J (1.2 lb/MW-hr).

- The proposed standard for SO_2 is the same for all turbines, regardless of size and fuel type. All new turbines would be required to meet an emission limit of 73 ng/J (0.58 lb/MW-hr). Alternatively, a fuel sulfur content limit of 0.05 percent by weight [500 parts per million (ppmw)] could be met.

- EPA expects that most owners or operators of new turbines would be able to comply with the NO_x limit without installing add-on emissions controls. Most new turbines already utilize lean premix technology, which has inherently low NO_x emissions. A few turbines may need to install a selective catalytic reduction (SCR) control device to meet the NO_x limit.

- EPA expects that all owners and operators of new turbines will comply with the option of demonstrating low sulfur content of their fuels rather than stack testing for SO_2. Fuel oil and pipeline natural gas contain low levels of sulfur and are widely available.

- EPA estimates that 355 new stationary combustion turbines would be subject to the rule, as proposed, by the end of the 5th year after the final rule takes effect.

- Comments may be submitted on the proposed action for 60 days following publication of the proposed rule in the Federal Register.

HEALTH/ENVIRONMENTAL BENEFITS

- The proposed rule would provide improvements in protecting human health and the environment by reducing pollutant emissions. The EPA estimates that the total pollutant reductions will be over 830 tons per year of criteria pollutants in the 5th year after the rule is final. The proposed rule would reduce NO_x and SO_2 emissions limits by over 80 and 93 percent, respectively.

- An output-based standard relates the emissions to the productive output of the process; in this case, pounds of emissions are related to the power output, or MW-hour. The output-based standards in the proposed rule would allow owners and operators the flexibility to meet their emission limit targets by increasing the efficiency of their turbines. The use of more efficient technologies reduces fossil fuel use, and reduces environmental impacts associated with the production and use of fossil fuels.

- Pollutants such as NO_x and SO_2 may cause both temporary and long-term respiratory symptoms, such as shortness of breath, changes in airway responsiveness, and increased susceptibility to respiratory infection.

- Nitrogen oxides can react in the air to form ground-level ozone. Ozone can cause coughing, shortness of breath, and aggravate asthma, and other chronic lung diseases such as emphysema and bronchitis. Ozone can lead to reduced lung function in both children and adults.

- NO_x and SO_2 also can form fine particle pollution. Exposure to fine particle pollution is associated with significant adverse health effects including shortness of breath, bronchitis, asthma attacks, heart attacks and premature death.

- Both NO_x and SO_2 are major precursors to acid rain, which, when deposited, are associated with acidification of soil and surface water.

COST

- EPA estimates the total nationwide annual costs for the rule, as proposed, to be \$3.4

million in the 5th year.

BACKGROUND

- The Clean Air Act requires EPA to promulgate NSPS for stationary combustion turbines. The standards must consider emission control technologies available and costs of control.

- New source performance standards are a statutory requirement under section 111 of the Clean Air Act. The original NSPS for stationary combustion turbines were promulgated under subpart GG of 40 CFR part 60 in 1979. Under the Clean Air Act, the Administrator is required to review the standards at least every 8 years, and revise the standards as appropriate.

- Since EPA originally promulgated new source performance standards for stationary gas turbines in 1979, technological advances have led to improvements in:
  nitrogen oxide emissions control devices,
  emissions monitoring devices,
  emissions test methods,
  combustion efficiency and turbine design, and
  the composition of fuels used for gas turbines.

- The proposed standards reflect the performance and emissions of today's new stationary combustion turbines without the use of add-on controls.

FOR MORE INFORMATION

- To download the proposed rule from EPA's web site, go to "Recent Actions" at the following address: *http://www.epa.gov/ttn/oarpg.*

- For further information about the rule, contact Mr. Jaime Pagán at EPA's Office of Air Quality Planning and Standards at 919-541-5340.

- For other combustion-related regulations, visit EPA's Combustion Related Rules page at: *http://www.epa.gov/ttn/combust/list.html.*

Department of Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

May 31, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gregg Worley, Chief
Preconstruction/HAP Section
Air, Radiation Technology Branch
US EPA Region IV
61 Forsyth Street
Atlanta, GA 30303

Re: Determination of Applicability to Subpart KKKK
Keys Energy Services Stock Island Power Plant
PSD-FL-348

Dear Mr. Worley:

Enclosed are documents indicating the Department's intent to issue an air construction permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to Keys Energy Services for construction of a 48 megawatt simple cycle unit at the Stock Island Power Plant. The project is not subject to the Florida's Power Plant Siting procedure because it will generate no electricity from steam. The enclosed documents include: the "Intent to Issue Air Construction Permit;" the "Public Notice of Intent to Issue Air Construction Permit;" the Department's "Technical Evaluation and Preliminary Determination" including a draft determination of Best Available Control Technology; and the Draft Permit.

Please provide your comments on the Draft BACT determination and Draft Permit. The Department specifically requests EPA's determination of applicability to the proposed standard, 40 CFR 60, Subpart KKKK to the project. The recent proposed standard is applicable to combustion turbines that commence construction after February 18, 2005. The GE LM6000 PC SPRINT will not meet the proposed NO_x standard of KKKK without additional control such as proposed by the Department. Keys Energy Services has provided supporting documentation of a letter agreement (also enclosed) between the applicant and GE Packaged Power, Inc. dated February 18, 2005.

If you have any questions on these matters please contact me at 850/921-9523.

Sincerely,

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/al

Enclosures

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Mr. Greg Worley
Air Planning Branch
US EPA - Region 4
61 Forsyth St.
Atlanta, GA 30303

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Mr. Greg Worley
Air Planning Branch
US EPA - Region 4
61 Forsyth St.
Atlanta, GA 30303

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Bureau of Air Regulation, NSR
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Tallahassee, FL 32399-2400

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VIA E-MAIL
ORIGINAL VIA OVERNIGHT DELIVERY

February 18, 2005

Robert F. Anderson
General Manager, North American Sales
GE Packaged Power, Inc.
1333 West Loop South, Suite 1000
Houston, Texas 77027

RE: Contract for Fabrication and Construction of one LM6000 PC Sprint Combustion Turbine Based Simple Cycle Power Plant

Pursuant to our recent and ongoing discussions regarding the response of GE Packaged Power, Inc. (GE ENERGY) to the Florida Municipal Power Agency (FMPA) (FMPA and GE ENERGY are each referred to herein as a "Party" or collectively as the "Parties") All-Requirements Project Stock Island Combustion Turbine Unit 4 Combustion Turbine Generator Request for Quotations (the RFQ), we propose the following binding written contract (this Contract):

WHEREAS, FMPA has issued the RFQ and GE ENERGY has submitted a timely Gas Turbine Generator Commercial Proposal in response to the RFQ; and

WHEREAS, FMPA has evaluated all responses to the RFQ and now, pursuant to the terms hereof, desires to enter into this binding written contract to purchase one LM6000 PC Sprint combustion turbine based simple cycle generating set nominally rated at FORTY-FIVE (45) megawatts (MW) (the CT); and

WHEREAS, GE ENERGY desires to be contractually bound to fabricate and construct the CT and sell the CT to FMPA; and

WHEREAS, FMPA desires to be contractually bound to purchase the CT from GE ENERGY.

STATEMENT OF AGREEMENT

NOW, THEREFORE, in view of the foregoing premises and for and in consideration of the mutual benefits, covenants, and agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties, for themselves, their successors, and assigns, hereby agree as follows:

1. **RECITALS.** The above recitals are true and correct and are hereby incorporated into and made a material part of this Contract.

2. **CONSTRUCTION OF CT.** In consideration of a firm lump sum price of FOURTEEN MILLION TWO HUNDRED FORTY-THREE THOUSAND NINE DOLLARS ($14,243,009) to be paid by FMPA, GE ENERGY agrees to fabricate and construct one LM6000 PC Sprint combustion turbine based simple cycle generating set nominally rated at FORTY-FIVE (45) MW to fire fuel oil only to be located at Stock Island, Key West, Florida, in accordance with technical specifications and commercial terms and conditions mutually agreeable to the Parties.

3. **CANCELLATION.** If this Contract is canceled by either FMPA or GE after this date, for any reason, then the Party canceling this Contract shall pay to the other Party a cancellation fee in the amount of ONE HUNDRED THOUSAND DOLLARS ($100,000). Payment by the canceling Party of the foregoing cancellation fee shall be canceling Party's sole and exclusive liability and non-canceling Party's sole and exclusive remedy for cancellation of this Contract.

4. **EFFECTIVE DATE.** This Contract shall become effective as of the date last signed by a Party hereto.

5. **SEVERABILITY.** Wherever possible, each provision of this Contract shall be interpreted in such a manner as to be effective and valid under applicable law. Should any portion of this Contract be declared invalid for any reason, such declaration shall have no effect upon the remaining portions of this Contract. In the event any provision of this Contract is held by any tribunal of competent jurisdiction to be contrary to applicable law, the remaining provisions of this Contract shall remain in full force and effect.

6. **COUNTERPARTS.** This Contract may be executed in any number of counterparts, and signature pages exchanged by facsimile, and each counterpart shall be regarded for all purposes as an original, and such counterparts shall constitute, but one and the same instrument, it being understood that both Parties need not sign the same counterpart. The signature page of any counterpart, and facsimiles and photocopies thereof, may be appended to any other counterpart and when so appended shall constitute an original. In the event that any signature is delivered by facsimile transmission or by facsimile signature, such signature shall create a valid and binding obligation of the party executing (or on whose behalf such signature is executed) the Contract with the same force and effect as if such facsimile signature page were an original thereof.

Two originals of this Contract have been provided to you. If GE ENERGY agrees with and accepts this Contract please indicate such by dating and signing in the space provided below on both originals and return both originals to the undersigned, whereupon a fully executed original will be returned to you for your records.

Very truly yours,

FLORIDA MUNICIPAL POWER AGENCY

Roger A. Fontes
General Manager & CEO

Agreed to and Accepted By:

GE PACKAGED POWER, INC.

By: ____________________________

____
(Print Name of Signatory)

Its: ______________________

Date: ______________________

Cc: Stanley Armbruster, B&V
Fred Bryant, FMPA
Rick Casey, FMPA
Warren Ferguson, GE ENERGY
Jody Finklea, FMPA
Kevin Fleming, FMPA
Jim Hay, FMPA
Angela Morrison, HG&S
Russell Thompson, GE ENERGY

PERMITTEE:

Keys Energy Services
1001 James Street
Key West, Florida 33401-6100

ARMS Permit No.	0870003-007-AC
PSD Permit No.	PSD-FL-348
SIC No.	4911
Expires:	July 31, 2007

Authorized Representative:
Daniel Cassel
Director of Generation

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality. The proposed project authorizes the installation of one nominal 48 megawatts fuel oil-fired, simple cycle combustion turbine-electrical generator. This project additionally authorizes the installation of a nominal 1,000,000 gallon fuel oil storage tank and an additional water tank.

The project will be located at the Stock Island Power Plant near Key West, Monroe County. The physical address of the facility is 6900 Front Street, Stock Island. UTM coordinates for this facility are Zone 17; 425.65 km E; 2716.67 km N.

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 40 CFR 52.21. 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.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD Best Available Control Technology (BACT) Determination
Appendix GC General Conditions

Michael G. Cooke, Director
Division of Air Resource Management

Date:

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

The existing Stock Island Plant consists of two nominal 8.8 MW diesel generators, one nominal 23.5 MW simple cycle combustion turbine, two nominal 19.8 MW simple cycle combustion turbines and miscellaneous unregulated units. The proposed project is to install one nominal 48 MW simple cycle combustion turbine-electrical generator, one nominal 1,000,000 gallon fuel oil storage tank, and a water tank.

NEW EMISSIONS UNITS

The proposed project will result in the following new emissions units.

EU ID No.	Emissions Unit Description
011	General Electric LM 6000 PC SPRINT Combustion Turbine-Electrical Generator
012	One nominal 1,000,000 gallon Distillate Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

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

Title IV Acid Rain: This facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: This facility is a Title V major source of air pollution.

PSD Major Source: The project is located in an area designated as "attainment," "maintenance," or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is not one of the 28 PSD source categories, and is subject to the PSD applicability threshold of 250 tons per year. Potential emissions of at least one regulated pollutant exceed 250 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

1. NSPS Sources: The combustion turbine specified in this permit is also subject to regulation under the New Source Performance Standards for Stationary Gas Turbines, 40 CFR 60, Subpart GG~~, and may be subject to Proposed Subpart KKKK~~.

NESHAP: The National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart YYYY for combustion turbines does not apply because the facility is not a major source of HAPS.

RELEVANT DOCUMENTS

- Air Construction/PSD Permit application received on October 14, 2004;
- First Department Request for Additional Information (RAI) dated November 10, 2004;
- Response to First RAI received on January 18, 2005;
- Supplement to First RAI Response received on February 18, 2005;
- Second Department RAI dated February 17, 2005;
- Response to Second RAI received on April 13, 2005; and
- Intent to Issue Air Construction/PSD Permit distributed May 23, 2005.

SECTION II. ADMINISTRATIVE REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the South District Office, Florida Department of Environmental Protection, 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-3381. The phone number is 239/332-6975 and the fax number is 239/332-6969.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code.

4. General Conditions: The owner and operator are subject to, and shall operate under the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated 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 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified.

7. Permit Expiration: 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, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C.]

9. 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.]

10. Modifications: No emissions unit or facility subject to this permit 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.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. 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 Department's Bureau of Air Regulation and a copy to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

A. COMBUSTION TURBINE (EU 011) WATER INJECTION ONLY & ≤ 2,500 HOURS

This section of the permit addresses the following new emissions unit for the period during which the unit operates for 2,500 hours or less on a rolling 12-month total and with water injection only. Upon reaching the first rolling 12-month total of 2,501, section III.B. of this permit will supercede all conditions in this section(III.A.).

E.U. ID No.	Common Emission Unit Description
011	General Electric LM 6000 PC Sprint Combustion Turbine-Electrical Generator

Applicable Standards and Regulations

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for nitrogen oxides (NO_X), and particulate matter (PM_{10}). [Rule 62-212.400, F.A.C.]
2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.
   (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 GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (c) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** The Department
2 has made a ~~preliminary~~ determination~~, subject to approval by EPA,~~ that this regulation proposed on ~~January~~ February 18, 2005 does not apply to this project.

Performance Restrictions

3. Combustion Turbine: The permittee is authorized to install, tune, operate and maintain one simple cycle combustion turbine-electrical generator with spray intercooling and water injection (General Electric Model LM6000 PC SPRINT). The unit is designed to produce approximately 48 MW of electrical power at ISO conditions. [Applicant Request]
4. Permitted Capacity: The heat input to the combustion turbine from firing No. 2 fuel oil shall not exceed 434 MMBtu per hour (LHV) based on the following: 100% base load, lower heating value of No. 2 fuel oil, and a compressor inlet air temperature of 41° F. 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. Heat input rates will vary depending upon compressor conditions and the combustion turbine characteristics. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves on file with the Department.
   [Design, Rule 62-210.200, F.A.C. (Definition - PTE)]
5. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based

on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle conversion which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. [Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.] (See III.B. for BACT if increased hours of operation.)

6. Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)]

{Permitting note: Pipeline natural gas is currently unavailable to the Keys.}

7. Hours of Operation: The combustion turbine shall operate no more than 2,500 hours based on a 12-month rolling total without installing a selective catalytic reduction (SCR) system. Exceeding this restriction shall require the installation and operation of an SCR system as required in III.B. [Applicant Request, Rules 62-210.200, (PTE) and 62-212.400(2)(g), F.A.C.]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

9. 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 the 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.]

EMISSIONS CONTROLS

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

11. Water Injection Technology: The permittee shall install, calibrate, tune, operate, and maintain a water injection system designed to achieve the permitted NO_x emissions standards for the unit. [Applicant request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

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12. Future Selective Catalytic Reduction (SCR): The permittee shall design and build the project to facilitate and not to hamper or preclude the future installation of the SCR system. ~~The combustion turbine may operate without the use of the SCR system for an initial period during which the total hours of operation do not exceed 2,500 during any 12-month rolling total.~~ [Design and Rule 62-212.400, F.A.C.]

13. 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.]

EMISSIONS STANDARDS

14. Summary: The following table summarizes the emissions standards for each pollutant and total emissions in lb/hr and TPY for informational and convenience purposes (PTE) only, and shall not be considered permit limits. This table does not supersede any of the terms or conditions of this permit.

Pollutant	Emission Standard/Limit	Emissions (lb/hr)	Emissions (TPY)
NO_X	42 ppmvd @ 15% O_2	75.9	94.9
CO	30 ppmvd @ 15% O_2	33.0	41.0
SO_2	0.05 percent sulfur fuel oil	23.6	29.5
SAM	0.05 percent sulfur fuel oil	5.4	6.8
PM/PM_{10}	VE = 10% as surrogate	25.0 (front and back)	31.3
PM/PM_{10}	VE = 10% as surrogate	13.9 (front half)	17.4
VOC	16 ppmvd @ 15% O_2	10.0	12.6

Note: Annual emissions, for the purposes of this table only, are based on a 41° F temperature and 2,500 hours of full load operation.

15. Carbon Monoxide (CO):

CO emissions from the combustion turbine shall not exceed 30.0 ppmvd @15% O_2. CO emissions shall not exceed 33.0 pounds per hour. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with EPA Method 10 and the requirements of this permit.
[Rule 62-212.400, F.A.C. (PSD Avoidance)]

16. Nitrogen Oxides (NO_X):

This emissions limit applies during the initial phase of operation when the combustion turbine operates no more than 2,500 hours based on a 12-month rolling total:

NO_X emissions from the combustion turbine shall not exceed a BACT emission limit of 42 ppmvd @15% O_2 during initial and annual tests nor exceed 42.0 ppmvd @15% O_2 on a 24-hour block average while firing fuel oil. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with 40 CFR Part 60 Subpart GG and based on a 24-hour block average for data collected from the continuous emissions monitor.
[Rule 62-212.400, F.A.C. (BACT)]

4 ~~*{Permitting note: Pipeline natural gas is currently unavailable to the Keys. However, for a similar unit operating on natural gas and for a comparable number of hours, a BACT limit would likely be set at 15 ppmvd @ 15% O₂.}*~~

17. Particulate Matter (PM/PM_{10}) and Visible Emissions (VE)

Emissions of PM and PM_{10} shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. Visible emissions from the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM10 emission limits. [Rules 62-4.070(3) and 62-212.400, F.A.C. (PSD Applicability)]

18. Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

Emissions of SAM and SO_2 shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. SAM and SO_2 emissions shall not exceed 6.8 and 29.5 tons per year, respectively. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the fuel records specified by this permit.[Rules 62-4.070(3), and 62-212.400, F.A.C. (BACT)].

19. Volatile Organic Compounds (VOC):

VOC emissions from the combustion turbine shall not exceed 16.0 ppmvd corrected to 15% oxygen for each fuel. VOC emissions shall not exceed 10.0 pounds per hour. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting initial tests in accordance with EPA Methods 25 and/or 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Section III.A. of this permit. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

20. Definitions:

(a) *Excess Emissions* are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

(b) *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(246), F.A.C.]

(c) *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]

(d) *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(160), F.A.C.]

21. Startup, Shutdown, Malfunction: 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 case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A written report summarizing each malfunction resulting in excess emissions shall be submitted in a quarterly report. [Rule 62-210.700(1) and (6), F.A.C.]

(a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for more than 2 hours in any 24-hour block averaging period.
[Design; Rule 62-210.700(1) and (5), F.A.C.]

(b) During all startups, shutdowns, and malfunctions, the NO_x continuous emissions monitoring System (CEMS) shall monitor and record emissions. Up to 2 hours (120 minutes) of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. However, only data obtained during startups, shutdowns, and documented malfunctions may be used for the 2 hour exclusion period. Other arbitrary high readings may not be excluded from compliance averaging periods. [Rule 62-210.700(1) and (5), F.A.C.]

(c) A documented malfunction means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile, or electronic mail. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

22. Prohibition: 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. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

23. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. [Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

24. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

(a) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources;

(b) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources;

(c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines; and

(d) EPA Method 25 or 25A - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions).

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure specified in Rule 62-297.620, F.A.C.

A. COMBUSTION TURBINE (EU 011) WATER INJECTION ONLY & ≤ 2,500 HOURS

25. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial NSPS performance tests and at least 15 days prior to any other required tests. [40 CFR 60.7, 40 CFR 60.8 and Rule 62-297.310(7)(a)9., F.A.C.]

26. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NO_X, VOC, and visible emissions. Initial NO_X performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and shall also be converted into units of the NSPS emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.]

27. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X, CO and visible emissions from the combustion turbine for each fuel. If conducted at permitted capacity, NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). In the event that the operation of the CT is less than 400 hours per year, annual testing is not required for that year. [Rule 62-297.310(7)(a), F.A.C.]

28. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NO_X and visible emissions from the combustion turbine. VOC emission tests are not required prior to permit renewal provided the CO emission standards are met. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. [Rule 62-297.310(7)(a)3., F.A.C.]

29. Tests After Major Repairs or Replacements: The Department may require that additional compliance testing be conducted within 90 days after major repairs or replacements are performed. [Rule 62-297.310(7)(a)4., F.A.C.]

30. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

31. 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.]

32. Applicable Test Procedures

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. [Rule 62-297.310(4)(a)1., F.A.C.]

2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)2., F.A.C.]

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

(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)(d), F.A.C.]

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

(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)(b), F.A.C.]

34. 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.]

CONTINUOUS MONITORING REQUIREMENTS

35. NO_X CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NO_X and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NO_X monitoring devices shall comply with the requirements of 40 CFR 60.334(b) for 40 CFR Part 75 monitoring systems. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location. [Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

36. <u>NO_X CEMS Data Requirements</u>:

(a) Installation. The CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and 40 CFR 60.334(b).

(b) 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. A valid hour is one in which at least 1 data point is recorded in each quadrant during which the unit was operating.

(c) Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (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. The Department may request a written report summarizing the excess
5 emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition ~~41~~ 42 of this permit.

(d) Data Exclusion. As provided in III.A. 21-22, valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit. Up to 2 hours of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-297.520, F.A.C and 40 CFR 60.7].

37. <u>Hours of Operation</u>: Using a component of the gas turbine control system, the permittee shall monitor and record the hours of gas turbine operation. Within five working days following the end of each calendar month, the permittee shall record the total hours of operation (including hours during startups, shutdowns, and malfunctions) for the current month, and the total hours of operation for the current month plus the preceding 11 months.
[Rule 62-204.070, F.A.C. and Applicant Request]

COMPLIANCE DEMONSTRATIONS

38. <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.]

39. <u>Fuel Records</u>: The permittee shall demonstrate compliance with the fuel sulfur limits for fuel oil specified in this permit by maintaining records required by 40 CFR 60.334 and 60.335. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

40. <u>Monthly Operations Summary</u>: By the fifth calendar day of each month, the permittee shall record the hours of operation and amount of fuel fired for the combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. All hours of operation (including hours during startups,

shutdowns, and malfunctions) shall be included in the demonstration of compliance with the 12-month fuel usage limitations. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

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

42. Excess Emissions Reporting:

    (a) If excess NO_X or visible emissions 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) NSPS Semi-Annual Reports. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. 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 to the Compliance Authority.

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

    (c) SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NOx emissions in excess of the BACT permit standards at Specific Condition 16 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.

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

43. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours 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.]

44. Hours of Operation: Within ten working days following the first consecutive 12-month period in which the hours of operation exceed 2,500, the permittee shall notify the Compliance Authority. The notification shall include a summary of operation for the last 12 months, and the expected date of initial operation of the SCR system for the control of NO_X as required by III.B. [Rule 62-204.070, F.A.C., and Applicant Request]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS

B. COMBUSTION TURBINE (EU 011) WATER INJECTION AND SCR & > 2,500 HOURS

6 This section of the permit addresses the following new emissions unit upon exceeding 2,500 hours or operation on a 12-month rolling total and thereafter. Upon exceeding 2,500 hours ^ the provisions of III.B. superceed III.A. for the rest of the operating life of the unit. BACT is water injection and SCR. of operation on a 12-month rolling total,

E.U. ID NO.	COMMON EMISSION UNIT DESCRIPTION
011	General Electric LM 6000 PC Sprint Combustion Turbine-Electrical Generator

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for nitrogen oxides (NO_X) and particulate matter (PM_{10}). Practicably enforceable limits have been established for sulfur dioxide (SO_2), and sulfuric acid mist (SAM) to avoid BACT determinations for these pollutants. [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (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

   (d) **Subpart GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (e) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** The Department has made a ~~preliminary~~ determination, ~~subject to approval by EPA~~, that this regulation proposed on ~~January 18,~~ February 2005 does not apply to this project.

PERFORMANCE RESTRICTIONS

3. Combustion Turbine: The permittee is authorized to install, tune, operate and maintain one simple cycle combustion turbine-electrical generator with spray intercooling and water injection (General Electric Model LM6000 PC SPRINT). The unit is designed to produce approximately 48 MW of electrical power at ISO conditions. [Applicant Request]

4. Permitted Capacity: The heat input to the combustion turbine from firing No. 2 fuel oil shall not exceed 434 MMBtu per hour (LHV) based on the following: 100% base load, lower heating value of No. 2 fuel oil, and a compressor inlet air temperature of 41° F. If different from the information provided in accordance with Specific Condition III.A.4, 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. Heat input rates will vary depending upon compressor conditions and the combustion turbine characteristics. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves on file with the Department.
   [Design, Rule 62-210.200, F.A.C. (Definition - PTE)]

5. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle operation which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. [Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.]

6. Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. Total fuel usage shall not exceed 13,600,000 gallons of fuel oil during any consecutive 12 months. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)].

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7. Hours of Operation: The combustion turbine may operate 8,760 hours per year. [Applicant Request, Rule 62-210.200, F.A.C. (PTE)]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3), Rule 62-212.400, F.A.C. (BACT)]

9. 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 the 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.]

EMISSIONS CONTROLS

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

11. Water Injection Technology: The permittee shall install, calibrate, tune, operate, and maintain a water injection system designed to achieve the permitted NO_x emissions standards for the unit in conjunction with the SCR system.
[Applicant request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

12. Selective Catalytic Reduction (SCR): Within two months after exceeding the 12-month rolling total of 2,500 operating hours, the permittee shall install, calibrate, tune operate and maintain an SCR system designed to achieve the permitted NOx emissions standards for the unit in conjunction with the water injection system. [Design and Rule 62-212.400, F.A.C.]

13. 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.]

EMISSIONS STANDARDS

14. Summary: The following table summarizes the emissions standards for each pollutant and total emissions in lb/hr and TPY for informational and convenience purposes (PTE) only and shall not be considered permit limits. This table does not supersede any of the terms or conditions of this permit.

Pollutant	Emission Standard/Limit	Emissions (lb/hr)	Emissions (TPY)
NO_X	9 ppmvd @ 15% O_2 24-hr block average	16.3	36.0
CO	20.0 ppmvd @ 15% O_2	20.0	44.2
SO_2	0.05 percent sulfur fuel oil	23.6	39.9
SAM	0.05 percent sulfur fuel oil	[illegible].4	6.9
PM/PM_{10}	VE = 10% as surrogate 0.05 percent sulfur fuel oil	25.0	109.5
PM	VE = 10% as surrogate 0.05 percent sulfur fuel oil	25.0	109.5
VOC	8.0 ppmvd @ 15% O_2	5.0	11.0

9 | Note: Annual emissions, for the purposes of this table only, are based on ~~an ambient~~ ~41°F temperature~~s~~ and the equivalent of 4,420 hour of full load operation. PM/PM_{10} estimates are based on the equivalent of 8,760 hours of full load operation.

15. Carbon Monoxide (CO):

CO emissions from the combustion turbine shall not exceed 20.0 ppmvd @15% O_2. CO emissions shall not exceed 20.0 lbs per hour. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with EPA Method 10 and the requirements of this permit. [Rule 62-212.400, F.A.C. (PSD Avoidance)]

16. Nitrogen Oxides (NO_x):

The combustion turbine and SCR system shall be designed and constructed to meet an emission limit of 5.0 ppmvd @15% O_2. This shall be demonstrated during each initial test following installation of new catalyst. During normal operation, NO_x emissions shall not exceed 9.0 ppmvd @15% O_2 on a 24-hour block average. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with 40 CFR Part 60 Subpart GG and based on a 24-hour block average for data collected from the continuous emissions monitor.
[Rule 62-212.400, F.A.C. (BACT)]

{Permitting note: The 5.0 ppmvd value reflects BACT. The 9.0 ppmvd value is based on the fuel use limitation that would limit NO_x emissions to less than 40 tons per year. The Department will revise the higher long term limit downward in conjunction with any future applications that will increase fuel use above 13,600,000 gallons per year.}

17. Ammonia (NH_3)

The ammonia slip rate shall be limited to 10.0 ppmvd @ 15% O_2.
[Rule 62-212.400, F.A.C. (BACT).

18. Particulate Matter (PM/PM_{10})

Emissions of PM and PM_{10} shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. Visible emissions from the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM_{10} emission limits. [Rule 62-212.400, F.A.C. (PSD Applicability)]

19. Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

Emissions of SAM, and SO_2 shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. SAM and SO_2 emissions shall not exceed 6.9 and 39.9 tons per year, respectively. Compliance with the SO_2 limit provides assurance that SAM emissions stay within permitted limits. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the records specified by this permit. [Rule 62-212.400, F.A.C. (BACT)].

20. Volatile Organic Compounds (VOC):

VOC emissions from the combustion turbine shall not exceed 8.0 ppmvd corrected to 15% oxygen for each fuel. VOC emissions shall not exceed 5.0 pounds per hour. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting initial tests in accordance with EPA Methods 25 and/or 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Section III.B. of this permit. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

21. Definitions:

(a) *Excess Emissions* are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

(b) *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(246), F.A.C.]

(c) *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]

(d) *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(160), F.A.C.]

22. Startup, Shutdown, Malfunction: 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 case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A written report summarizing each malfunction resulting in excess emissions shall be submitted in a quarterly report. [Rule 62-210.700(1) and (6), F.A.C.]

(a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for more than 2 hours in any 24-hour block averaging period.
[Design; Rule 62-210.700(1) and (5), F.A.C.]

(b) During all startups, shutdowns, and malfunctions, the NO_x continuous emissions monitoring System (CEMS) shall monitor and record emissions. Up to 2 hours (120 minutes) of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. However, only data obtained during startups, shutdowns, and documented malfunctions may be used for the 2 hour exclusion period. Other arbitrary high readings may not be excluded from compliance averaging periods. [Rule 62-210.700(1) and (5), F.A.C.]

(c) A documented malfunction means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile, or electronic mail. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

23. Prohibition: 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. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

24. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. KEYS shall advise the Department of any requirements within the cited rule that would be incompatible with the operation of an SCR system or unadvisable due to storm design criteria. [Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

25. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

(a) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources;

(b) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources;

(c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines.

(d) EPA Method 25 or 25A

10 ~~(e)~~ - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions); and

(f) Conditional Test Method 027 – Measurement of Ammonia Slip.

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure specified in Rule 62-297.620, F.A.C.

26. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial NSPS performance tests and at least 15 days prior to any other required tests. [40 CFR 60.7, 40 CFR 60.8 and Rule 62-297.310(7)(a)9., F.A.C.]

27. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NO_X, VOC, ammonia slip and visible emissions. Initial NO_X performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and shall also be converted into units of the NSPS emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.]

28. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X, CO, and visible emissions from the combustion turbine for each fuel. Testing for ammonia slip is required during the first scheduled annual performance tests after the cumulative hours of operation exceed 1,500 actual hours starting from the initial installation of the SCR catalyst. Thereafter, ammonia testing is required during the first scheduled annual performance tests after subsequent cumulative 1,500 hours of operation or after regeneration, replacement or addition to the SCR catalyst system. If conducted at permitted capacity, NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). In the event that the operation of the CT is less than 400 hours per year, annual testing is not required for that year. [Rule 62-297.310(7)(a), F.A.C.]

29. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NO_X, and visible emissions from the combustion turbine. VOC emission tests are not required prior to permit renewal provided the CO emission standards are met. Testing for ammonia slip meeting the requirements of Condition 26, Annual Performance Tests will meet the requirements of this condition. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. [Rule 62-297.310(7)(a)3., F.A.C.]

30. Tests After Major Repairs or Replacements: The Department may require that additional compliance testing be conducted within 90 days after major repairs or replacements are performed. [Rule 62-297.310(7)(a)4., F.A.C.]

31. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve

downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

32. 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.]

33. Applicable Test Procedures

    (a) Required Sampling Time.

        1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. [Rule 62-297.310(4)(a)1., F.A.C.]

        2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)2., F.A.C.]

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

    (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)(d), F.A.C.]

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

    (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)(b), F.A.C.]

35. 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.]

CONTINUOUS MONITORING REQUIREMENTS

36. NO_X CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NO_X and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NO_X monitoring devices shall comply with the requirements of 40 CFR 60.334(b) for 40 CFR Part 75 monitoring systems. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location. [Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

37. NO_X CEMS Data Requirements:

    (a) Installation. The CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and 40 CFR 60.334(b).

    (b) 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. A valid hour is one in which at least 1 data point is recorded in each quadrant during which the unit was operating.

    (c) Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (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. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific conditions of this permit.

    (d) Data Exclusion. As provided in III.B. 21-22, valid hourly emission rates shall not include periods of startup, shutdown, or documented malfunction as described under the excess emissions requirements of this permit. Up to 2 hours of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions.

    [Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-297.520, F.A.C and 40 CFR 60.7].

38. Hours of Operation: Using a component of the gas turbine control system, the permittee shall monitor and record the hours of gas turbine operation. Within five working days following the end of each calendar month, the permittee shall record the total hours of operation (including startups, shutdowns, and malfunctions) for the current month, and the total hours of operation for the current month plus the preceding 11 months.
[Rule 62-204.070, F.A.C., and Applicant Request]

COMPLIANCE DEMONSTRATIONS

39. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 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.]

40. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits for fuel oil specified in this permit by maintaining records required by 40 CFR 60.334 and 60.335 and the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

41. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of operation and amount of each fuel fired for the combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. All hours of operation shall be included in the demonstration of compliance with the 12-month fuel usage limitations. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

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

43. Excess Emissions Reporting:

(a) If excess NO_X or visible emissions occur due to malfunction, the permittee shall notify the Compliance Authority within one (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) NSPS Semi-Annual Reports: For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. 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 to the Compliance Authority.

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

(c) SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NOx emissions in excess of the BACT permit standards at Specific Condition 16 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.

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

44. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual fuel usage 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.]

SECTION IV. INSIGNIFICANT EMISSIONS UNITS

DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
012	One distillate fuel oil storage tank for Combustion Turbine Unit 4 (approximately 1.0 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: As revised October 15, 2003, NSPS Subpart K does not apply to storage vessels which store a liquid with a vapor pressure less than 3.5 kPa.

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 1.0 million gallon distillate fuel oil storage tank designed to provide low sulfur fuel oil to Combustion Turbine Unit 4 or any other units on the site. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

   {Note: Emissions of VOC form this unit are estimated to be less than one ton per year.}

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.]

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

May 31, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33041-6100

Re: Keys Energy Services Stock Island Power Plant
Combustion Turbine Unit 4 – GE LM6000 SPRINT
File No. 0870003-007-AC (PSD-FL-348)

Dear Mr. Cassel:

Enclosed are documents indicating the Department's intent to issue an air construction permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to Keys Energy Services for construction of a 48 megawatt simple cycle unit at the Stock Island Power Plant. The documents include: the "Intent to Issue Air Construction Permit;" the "Public Notice of Intent to Issue Air Construction Permit;" the Department's "Technical Evaluation and Preliminary Determination" including a draft determination of Best Available Control Technology; and the Draft Permit.

The Public Notice must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven (7) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Mr. A. A. Linero, Program Administrator, South Permitting at the above letterhead address. If you have any questions, please call Debbie Nelson at 850/921-9537 or Mr. Linero at 850/921-9523.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer, Chief,
Bureau of Air Regulation

TLV/aal

Enclosures

In the Matter of an
Application for Permit by:

Keys Energy Services (KEYS)
1001 James Street
Key West, Florida 33041-6100

Authorized Representative:
Mr. Daniel Cassel, Director of Generation

DEP File No. 0870003-007-AC
Draft Permit No. PSD-FL-348
KEYS Stock Island Power Plant
48 MW Combustion Turbine Unit 4

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD), copy of DRAFT Permit attached, for the proposed project as detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination for the reasons stated below.

The applicant, Keys Energy Services, applied on October 14, 2004 (application revised on April 13, 2005) to the Department for an air construction permit for a nominal 48 megawatt simple combustion turbine project at the Stock Island Power Plant near Key West, Monroe County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit is required.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting 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 Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

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

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

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

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

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 Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6/2/05 to the persons listed:

Daniel Cassel, KEYS*
Edward Garcia, KEYS
Frederick Bryant, FMPA*
Susan Schumann, FMPA
Mayor, Key West
Chair, Monroe County BCC
Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Ron Blackburn, DEP SD
Stanley Armbruster, P.E., B&V

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. Harvey 6/2/05
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0870003-007-AC (PSD-FL-348)

KEYS Stock Island Power Plant Combustion Turbine Unit 4
Monroe County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Keys Energy Services to construct a nominal 48 megawatt (MW) simple cycle combustion turbine at the existing Stock Island Power Plant near Key West, Monroe County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of nitrogen oxides (NO_X) and particulate matter (PM/PM_{10}). The applicant's address is Keys Energy Services (KEYS), 1001 James Street, Key West, Florida 33041-6100.

The applicant proposes to construct a new combustion turbine-electrical generator (Combustion Turbine Unit 4). The primary components are: one nominal 48 MW General Electric LM6000 PC combustion turbine-electrical generator with spray intercooling (SPRINT); a 60-foot exhaust stack; a nominal 1,000,000 gallon fuel oil storage tank; a new water tank; and other associated support equipment.

Combustion Turbine Unit 4 will be permitted to operate 2,500 hours per year while firing low sulfur fuel oil (0.05 percent sulfur). Water injection into the combustion area will be practiced for NO_X control.

The Department has determined that BACT for NO_X is 42.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmvd @15% O_2) under the very special circumstances of this project including location, lack of natural gas supply, low annual emissions for the project, installation of a single unit, etc. This limit will be achieved by water injection. Future increases in hours of operation will require installation of a selective catalytic reduction (SCR).

Emissions of carbon monoxide (CO), PM/PM_{10}, sulfuric acid mist (SAM), sulfur dioxide (SO_2), and VOC will be minimized by the efficient, high-temperature combustion of low sulfur fuel oil. A BACT determination was not required for CO, SAM, SO_2, or VOC.

KEYS' estimates of maximum potential annual emissions from Combustion Turbine Unit 4 are summarized in the following table. Actual emissions will be substantially less than estimated because much of the operation will be under low load conditions. For example, KEYS estimates that if it actually operates the unit for 2,500 hours per year, emissions will actually be less than 60 tons per year of NO_X considering low load versus the estimate of 95 given below.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	34	100	No
Pb	0.013	0.6	No
NO_X	95	40	Yes
PM/PM_{10}	31/31	25/15	Yes
SO_2	30	40	No
SAM	<7	7	No
VOC	7	40	No

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 (i.e. PSD Class II Areas) Therefore; multi-source modeling was not required for ambient air quality standards Class II increments.

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southeast District Office
400 North Congress Avenue
West Palm Beach, FL 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

Dept. of Environmental Protection
South District Branch Office
2796 Overseas Highway, Suite 221
Marathon, Florida 33050
Telephone: 305/289-2310

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Program Administrator, South Permitting Section, Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/Air/permitting/construction/stockisland.htm

PERMITTEE:

Keys Energy Services
1001 James Street
Key West, Florida 33401-6100

ARMS Permit No.	0870003-007-AC
PSD Permit No.	PSD-FL-348
SIC No.	4911
Expires:	July 31, 2007

Authorized Representative:
Daniel Cassel
Director of Generation

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality. The proposed project authorizes the installation of one nominal 48 megawatts, fuel oil-fired, simple cycle combustion turbine-electrical generator. This project additionally authorizes the installation of a nominal 1,000,000 gallon fuel oil storage tank and an additional water tank.

The project will be located at the Stock Island Power Plant near Key West, Monroe County. The physical address of the facility is 6900 Front Street, Stock Island. UTM coordinates for this facility are Zone 17; 425.65 km E; 2716.67 km N.

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 40 CFR 52.21. 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.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD	Best Available Control Technology (BACT) Determination
Appendix GC	General Conditions

Michael G. Cooke, Director
Division of Air Resource Management

Date:

FACILITY DESCRIPTION

The existing Stock Island Plant consists of two nominal 8.8 MW diesel generators, one nominal 23.5 MW simple cycle combustion turbine, two nominal 19.8 MW simple cycle combustion turbines and miscellaneous unregulated units. The proposed project is to install one nominal 48 MW simple cycle combustion turbine-electrical generator, one nominal 1,000,000 gallon fuel oil storage tank, and a water tank.

NEW EMISSIONS UNITS

The proposed project will result in the following new emissions units.

EU ID No.	Emissions Unit Description
011	General Electric LM 6000 PC SPRINT Combustion Turbine-Electrical Generator
012	One nominal 1,000,000 gallon Distillate Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

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

Title IV Acid Rain: This facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: This facility is a Title V major source of air pollution.

PSD Major Source: The project is located in an area designated as "attainment," "maintenance," or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is not one of the 28 PSD source categories, and is subject to the PSD applicability threshold of 250 tons per year. Potential emissions of at least one regulated pollutant exceed 250 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS Sources: The combustion turbine specified in this permit is also subject to regulation under the New Source Performance Standards for Stationary Gas Turbines, 40 CFR 60, Subpart GG and may be subject to Proposed Subpart KKKK.

NESHAP: The National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart YYYY for combustion turbines does not apply because the facility is not a major source of HAPS.

RELEVANT DOCUMENTS

- Air Construction/PSD Permit application received on October 14, 2004;
- First Department Request for Additional Information (RAI) dated November 10, 2004;
- Response to First RAI received on January 18, 2005;
- Supplement to First RAI Response received on February 18, 2005;
- Second Department RAI dated February 17, 2005;
- Response to Second RAI received on April 13, 2005; and
- Intent to Issue Air Construction/PSD Permit distributed May 23, 2005.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the South District Office, Florida Department of Environmental Protection, 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-3381. The phone number is 239/332-6975 and the fax number is 239/332-6969.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code.

4. General Conditions: The owner and operator are subject to, and shall operate under the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated 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 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified.

7. Permit Expiration: 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, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C.]

9. 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.]

10. Modifications: No emissions unit or facility subject to this permit 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.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. 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 Department's Bureau of Air Regulation and a copy to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. COMBUSTION TURBINE (EU 011) WATER INJECTION ONLY & ≤ 2,500 HOURS

This section of the permit addresses the following new emissions unit for the period during which the unit operates for 2,500 hours or less on a rolling 12-month total and with water injection only. Upon reaching the first rolling 12-month total of 2,501, section III.B. of this permit will supercede all conditions in this section(III.A.).

E.U. ID No.	Common Emission Unit Description
011	General Electric LM 6000 PC Sprint Combustion Turbine-Electrical Generator

Applicable Standards and Regulations

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for nitrogen oxides (NO_X), and particulate matter (PM_{10}). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (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 GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (c) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** The Department has made a preliminary determination subject to approval by EPA, that this regulation proposed on January 18, 2005 does not apply to this project.

Performance Restrictions

3. Combustion Turbine: The permittee is authorized to install, tune, operate and maintain one simple cycle combustion turbine-electrical generator with spray intercooling and water injection (General Electric Model LM6000 PC SPRINT). The unit is designed to produce approximately 48 MW of electrical power at ISO conditions. [Applicant Request]

4. Permitted Capacity: The heat input to the combustion turbine from firing No. 2 fuel oil shall not exceed 434 MMBtu per hour (LHV) based on the following: 100% base load, lower heating value of No. 2 fuel oil, and a compressor inlet air temperature of 41° F. 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. Heat input rates will vary depending upon compressor conditions and the combustion turbine characteristics. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves on file with the Department.
   [Design, Rule 62-210.200, F.A.C. (Definition - PTE)]

5. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle conversion which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. [Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.] (See III.B. for BACT if increased hours of operation.)

6. Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)]

{Permitting note: Pipeline natural gas is currently unavailable to the Keys.}

7. Hours of Operation: The combustion turbine shall operate no more than 2,500 hours based on a 12-month rolling total without installing a selective catalytic reduction (SCR) system. Exceeding this restriction shall require the installation and operation of an SCR system as required in III.B. [Applicant Request, Rules 62-210.200, (PTE) and 62-212.400(2)(g), F.A.C.]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

9. 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 the 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.]

EMISSIONS CONTROLS

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

11. Water Injection Technology: The permittee shall install, calibrate, tune, operate, and maintain a water injection system designed to achieve the permitted NO_x emissions standards for the unit. [Applicant request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

12. Future Selective Catalytic Reduction (SCR): The permittee shall design and build the project to facilitate and not to hamper or preclude the future installation of the SCR system. The combustion turbine may operate without the use of the SCR system for an initial period during which the total

hours of operation do not exceed 2,500 during any 12-month rolling total. [Design and Rule 62-212.400, F.A.C.]

13. 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.]

EMISSIONS STANDARDS

14. Summary: The following table summarizes the emissions standards for each pollutant and total emissions in lb/hr and TPY for informational and convenience purposes (PTE) only, and shall not be considered permit limits. This table does not supersede any of the terms or conditions of this permit.

Pollutant	Emission Standard/Limit	Emissions (lb/hr)	Emissions (TPY)
NO_X	42 ppmvd @ 15% O_2	75.9	94.9
CO	30 ppmvd @ 15% O_2	33.0	41.0
SO_2	0.05 percent sulfur fuel oil	23.6	29.5
SAM	0.05 percent sulfur fuel oil	5.4	6.8
PM/PM_{10}	VE = 10% as surrogate	25.0 (front and back)	31.3
PM/PM_{10}	VE = 10% as surrogate	13.9 (front half)	17.4
VOC	16 ppmvd @ 15% O_2	10.0	12.6

Note: Annual emissions, for the purposes of this table only, are based on a 41° F temperature and 2,500 hours of full load operation.

15. Carbon Monoxide (CO):

CO emissions from the combustion turbine shall not exceed 30.0 ppmvd @15% O_2. CO emissions shall not exceed 33.0 pounds per hour. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with EPA Method 10 and the requirements of this permit.
[Rule 62-212.400, F.A.C. (PSD Avoidance)]

16. Nitrogen Oxides (NO_X):

This emissions limit applies during the initial phase of operation when the combustion turbine operates no more than 2,500 hours based on a 12-month rolling total:

NO_X emissions from the combustion turbine shall not exceed a BACT emission limit of 42 ppmvd @15% O_2 during initial and annual tests nor exceed 42.0 ppmvd @15% O_2 on a 24-hour block average while firing fuel oil. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with 40 CFR Part 60 Subpart GG and based on a 24-hour block average for data collected from the continuous emissions monitor.
[Rule 62-212.400, F.A.C. (BACT)]

{Permitting note: Pipeline natural gas is currently unavailable to the Keys. However, for a similar unit operating on natural gas and for a comparable number of hours, a BACT limit would likely be set at 15 ppmvd @ 15% O_2.}

17. Particulate Matter (PM/PM_{10}) and Visible Emissions (VE)

Emissions of PM and PM_{10} shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. Visible emissions from the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM10 emission limits. [Rules 62-4.070(3) and 62-212.400, F.A.C. (PSD Applicability)]

18. Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

Emissions of SAM and SO_2 shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. SAM and SO_2 emissions shall not exceed 6.8 and 29.5 tons per year, respectively. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the fuel records specified by this permit.[Rules 62-4.070(3), and 62-212.400, F.A.C. (BACT)].

19. Volatile Organic Compounds (VOC):

VOC emissions from the combustion turbine shall not exceed 16.0 ppmvd corrected to 15% oxygen for each fuel. VOC emissions shall not exceed 10.0 pounds per hour. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting initial tests in accordance with EPA Methods 25 and/or 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Section III.A. of this permit. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

20. Definitions

(a) *Excess Emissions* are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

(b) *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(246), F.A.C.]

(c) *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]

(d) *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(160), F.A.C.]

21. Startup, Shutdown, Malfunction: 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 case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A written report summarizing each malfunction resulting in excess emissions shall be submitted in a quarterly report. [Rule 62-210.700(1) and (6), F.A.C.]

(a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for more than 2 hours in any 24-hour block averaging period. [Design; Rule 62-210.700(1) and (5), F.A.C.]

(b) During all startups, shutdowns, and malfunctions, the NO_x continuous emissions monitoring System (CEMS) shall monitor and record emissions. Up to 2 hours (120 minutes) of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. However, only data obtained during startups, shutdowns, and documented malfunctions may be used for the 2 hour exclusion period. Other arbitrary high readings may not be excluded from compliance averaging periods. [Rule 62-210.700(1) and (5), F.A.C.]

(c) A documented malfunction means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile, or electronic mail. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

22. Prohibition: 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. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

23. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. [Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

24. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

(a) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources;

(b) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources;

(c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines; and

(d) EPA Method 25 or 25A - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions).

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure specified in Rule 62-297.620, F.A.C.

25. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial NSPS performance tests and at least 15 days prior to any other required tests. [40 CFR 60.7, 40 CFR 60.8 and Rule 62-297.310(7)(a)9., F.A.C.]

26. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NO_X, VOC, and visible emissions. Initial NO_X performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and shall also be converted into units of the NSPS emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.]

27. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X, CO, and visible emissions from the combustion turbine for each fuel. If conducted at permitted capacity, NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). In the event that the operation of the CT is less than 400 hours per year, annual testing is not required for that year. [Rule 62-297.310(7)(a), F.A.C.]

28. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NO_X, and visible emissions from the combustion turbine. VOC emission tests are not required prior to permit renewal provided the CO emission standards are met. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. [Rule 62-297.310(7)(a)3., F.A.C.]

29. Tests After Major Repairs or Replacements: The Department may require that additional compliance testing be conducted within 90 days after major repairs or replacements are performed. [Rule 62-297.310(7)(a)4., F.A.C.]

30. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

31. 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.]

32. Applicable Test Procedures

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. [Rule 62-297.310(4)(a)1., F.A.C.]

2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)2., F.A.C.]

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

(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)(d), F.A.C.]

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

(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)(b), F.A.C.]

34. 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.]

CONTINUOUS MONITORING REQUIREMENTS

35. NO_X CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NO_X and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NO_X monitoring devices shall comply with the

requirements of 40 CFR 60.334(b) for 40 CFR Part 75 monitoring systems. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location. [Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

36. NO_X CEMS Data Requirements:

(a) Installation. The CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and 40 CFR 60.334(b).

(b) 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. A valid hour is one in which at least 1 data point is recorded in each quadrant during which the unit was operating.

(c) Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (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. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition 41 of this permit.

(d) Data Exclusion. As provided in III.A. 21-22., valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit. Up to 2 hours of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-297.520, F.A.C and 40 CFR 60.7].

37. Hours of Operation: Using a component of the gas turbine control system, the permittee shall monitor and record the hours of gas turbine operation. Within five working days following the end of each calendar month, the permittee shall record the total hours of operation (including hours during startups, shutdowns, and malfunctions) for the current month, and the total hours of operation for the current month plus the preceding 11 months.
[Rule 62-204.070, F.A.C., and Applicant Request]

COMPLIANCE DEMONSTRATIONS

38. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 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.]

39. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits for fuel oil specified in this permit by maintaining records required by 40 CFR 60.334 and 60.335. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

40. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of operation and amount of fuel fired for the combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. All hours of operation (including hours during startups, shutdowns, and malfunctions) shall be included in the demonstration of compliance with the 12-month fuel usage limitations. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

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

42. Excess Emissions Reporting:

    (a) If excess NO_X or visible emissions 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) NSPS Semi-Annual Reports. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. 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 to the Compliance Authority.

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

    (c) SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NOx emissions in excess of the BACT permit standards at Specific Condition 16 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.

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

A. COMBUSTION TURBINE (EU 011) WATER INJECTION ONLY & ≤ 2,500 HOURS

43. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours 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.]

44. Hours of Operation: Within ten working days following the first consecutive 12-month period in which the hours of operation exceed 2,500, the permittee shall notify the Compliance Authority. The notification shall include a summary of operation for the last 12 months, and the expected date of initial operation of the SCR system for the control of NO_X as required by III.B. [Rule 62-204.070, F.A.C., and Applicant Request]

B. COMBUSTION TURBINE (EU 011) WATER INJECTION AND SCR & > 2,500 HOURS

This section of the permit addresses the following new emissions unit upon exceeding 2,500 hours or operation on a 12-month rolling total and thereafter. Upon exceeding 2,500 hours, the provisions of III.B. superceed III.A. for the rest of the operating life of the unit. BACT is water injection and SCR.

E.U. ID No.	Common Emission Unit Description
011	General Electric LM 6000 PC Sprint Combustion Turbine-Electrical Generator

Applicable Standards and Regulations

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for nitrogen oxides (NO_X), and particulate matter (PM_{10}). Practicably enforceable limits have been established for sulfur dioxide (SO_2), and sulfuric acid mist (SAM) to avoid BACT determinations for these pollutants. [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (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

   (d) **Subpart GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (e) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** The Department has made a preliminary determination, subject to approval by EPA, that this regulation proposed on January 18, 2005 does not apply to this project.

Performance Restrictions

3. Combustion Turbine: The permittee is authorized to install, tune, operate and maintain one simple cycle combustion turbine-electrical generator with spray intercooling and water injection (General Electric Model LM6000 PC SPRINT). The unit is designed to produce approximately 48 MW of electrical power at ISO conditions. [Applicant Request]

4. Permitted Capacity: The heat input to the combustion turbine from firing No. 2 fuel oil shall not exceed 434 MMBtu per hour (LHV) based on the following: 100% base load, lower heating value of No. 2 fuel oil, and a compressor inlet air temperature of 41° F. If different from the information provided in accordance with Specific Condition III.A.4, 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. Heat input rates will vary depending upon compressor conditions and the combustion turbine characteristics. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves on file with the Department.
   [Design, Rule 62-210.200, F.A.C. (Definition - PTE)]

5. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle operation which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. [Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.]

6. Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. Total fuel usage shall no exceed 13,600,000 gallons of fuel oil during any consecutive 12 months. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)].

7. Hours of Operation: The combustion turbine may operate 8,760 hours per year. [Applicant Request, Rule 62-210.200, F.A.C. (PTE)]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

9. 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 the 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.]

EMISSIONS CONTROLS

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

11. Water Injection Technology: The permittee shall install, calibrate, tune, operate, and maintain a water injection system designed to achieve the permitted NO_x emissions standards for the unit in conjunction with the SCR system.
[Applicant request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

12. Selective Catalytic Reduction (SCR): Within two months after exceeding the 12-month rolling total of 2,500 operating hours, the permittee shall install, calibrate, tune operate and maintain an SCR system designed to achieve the permitted NOx emissions standards for the unit in conjunction with the water injection system. [Design and Rule 62-212.400, F.A.C.]

13. 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.]

B. COMBUSTION TURBINE (EU 011) WATER INJECTION AND SCR & > 2,500 HOURS

EMISSIONS STANDARDS

14. Summary: The following table summarizes the emissions standards for each pollutant and total emissions in lb/hr and TPY for informational and convenience purposes (PTE) only and shall not be considered permit limits. This table does not supersede any of the terms or conditions of this permit.

Pollutant	Emission Standard/Limit	Emissions (lb/hr)	Emissions (TPY)
NO_X	9 ppmvd @ 15% O_2 24-hr block average	16.3	36.0
CO	20.0 ppmvd @ 15% O_2	20.0	44.2
SO_2	0.05 percent sulfur fuel oil	23.6	39.9
SAM	0.05 percent sulfur fuel oil	5.4	6.9
PM/PM_{10}	VE = 10% as surrogate 0.05 percent sulfur fuel oil	25.0	109.5
PM	VE = 10% as surrogate 0.05 percent sulfur fuel oil	25.0	109.5
VOC	8.0 ppmvd @ 15% O_2	5.0	11.0

Note: Annual emissions, for the purposes of this table only, are based on an ambient temperatures and the equivalent of 4,420 hour of full load operation. PM/PM_{10} estimates are based on the equivalent of 8,760 hours of full load operation.

15. Carbon Monoxide (CO):

CO emissions from the combustion turbine shall not exceed 20.0 ppmvd @15% O_2. CO emissions shall not exceed 20.0 lbs per hour. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with EPA Method 10 and the requirements of this permit. [Rule 62-212.400, F.A.C. (PSD Avoidance)]

16. Nitrogen Oxides (NO_X):

The combustion turbine and SCR system shall be designed and constructed to meet an emission limit of 5.0 ppmvd @15% O_2. This shall be demonstrated during each initial test following installation of new catalyst. During normal operation, NO_x emissions shall not exceed 9.0 ppmvd @15% O_2 on a 24-hour block average. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with 40 CFR Part 60 Subpart GG and based on a 24-hour block average for data collected from the continuous emissions monitor.
[Rule 62-212.400, F.A.C. (BACT)]

{Permitting note: The 5.0 ppmvd value reflects BACT. The 9.0 ppmvd value is based on the fuel use limitation that would limit NO_x emissions to less than 40 tons per year. The Department will revise the higher long term limit downward in conjunction with any future applications that will increase fuel use above 13,600,000 gallons per year.}

17. Ammonia (NH_3)

The ammonia slip rate shall be limited to 10.0 ppmvd @ 15% O_2.
[Rule 62-212.400, F.A.C. (BACT).

18. Particulate Matter (PM/PM_{10})

Emissions of PM and PM_{10} shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. Visible emissions from the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM_{10} emission limits. [Rule 62-212.400, F.A.C. (PSD Applicability)]

19. Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

Emissions of SAM, and SO_2 shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. SAM and SO_2 emissions shall not exceed 6.9 and 39.9 tons per year, respectively. Compliance with the SO_2 limit provides assurance that SAM emissions stay within permitted limits. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the records specified by this permit. [Rule 62-212.400, F.A.C. (BACT)].

20. Volatile Organic Compounds (VOC):

VOC emissions from the combustion turbine shall not exceed 8.0 ppmvd corrected to 15% oxygen for each fuel. VOC emissions shall not exceed 5.0 pounds per hour. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting initial tests in accordance with EPA Methods 25 and/or 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Section III.B. of this permit. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

21. Definitions

(a) *Excess Emissions* are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

(b) *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(246), F.A.C.]

(c) *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]

(d) *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(160), F.A.C.]

22. Startup, Shutdown, Malfunction: 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 case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A written report summarizing each malfunction resulting in excess emissions shall be submitted in a quarterly report. [Rule 62-210.700(1) and (6), F.A.C.]

   (a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for more than 2 hours in any 24-hour block averaging period. [Design; Rule 62-210.700(1) and (5), F.A.C.]

   (b) During all startups, shutdowns, and malfunctions, the NO_x continuous emissions monitoring System (CEMS) shall monitor and record emissions. Up to 2 hours (120 minutes) of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. However, only data obtained during startups, shutdowns, and documented malfunctions may be used for the 2 hour exclusion period. Other arbitrary high readings may not be excluded from compliance averaging periods. [Rule 62-210.700(1) and (5), F.A.C.]

   (c) A documented malfunction means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile, or electronic mail. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

23. Prohibition: 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. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

24. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. KEYS shall advise the Department of any requirements within the cited rule that would be incompatible with the operation of an SCR system or unadvisable due to storm design criteria. [Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

25. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

   (a) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources;

   (b) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources;

   (c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines.

   (d) EPA Method 25 or 25A

(e) - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions); and

(f) Conditional Test Method 027 – Measurement of Ammonia Slip.

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure specified in Rule 62-297.620, F.A.C.

26. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial NSPS performance tests and at least 15 days prior to any other required tests. [40 CFR 60.7, 40 CFR 60.8 and Rule 62-297.310(7)(a)9., F.A.C.]

27. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NO_X, VOC, ammonia slip and visible emissions. Initial NO_X performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and shall also be converted into units of the NSPS emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.]

28. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X, CO, and visible emissions from the combustion turbine for each fuel. Testing for ammonia slip is required during the first scheduled annual performance tests after the cumulative hours of operation exceed 1,500 actual hours starting from the initial installation of the SCR catalyst. Thereafter, ammonia testing is required during the first scheduled annual performance tests after subsequent cumulative 1,500 hours of operation or after regeneration, replacement or addition to the SCR catalyst system. If conducted at permitted capacity, NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). In the event that the operation of the CT is less than 400 hours per year, annual testing is not required for that year. [Rule 62-297.310(7)(a), F.A.C.]

29. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NO_X, and visible emissions from the combustion turbine. VOC emission tests are not required prior to permit renewal provided the CO emission standards are met. Testing for ammonia slip meeting the requirements of Condition 26, Annual Performance Tests will meet the requirements of this condition. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. [Rule 62-297.310(7)(a)3., F.A.C.]

30. Tests After Major Repairs or Replacements: The Department may require that additional compliance testing be conducted within 90 days after major repairs or replacements are performed. [Rule 62-297.310(7)(a)4., F.A.C.]

31. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100

percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

32. 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.]

33. Applicable Test Procedures

    (a) Required Sampling Time.

        1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. [Rule 62-297.310(4)(a)1., F.A.C.]

        2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)2., F.A.C.]

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

    (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)(d), F.A.C.]

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

    (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)(b), F.A.C.]

35. 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.]

CONTINUOUS MONITORING REQUIREMENTS

36. NO_X CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NO_X and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NO_X monitoring devices shall comply with the requirements of 40 CFR 60.334(b) for 40 CFR Part 75 monitoring systems. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location. [Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

37. NO_X CEMS Data Requirements:

    (a) Installation. The CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and 40 CFR 60.334(b).

    (b) 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. A valid hour is one in which at least 1 data point is recorded in each quadrant during which the unit was operating.

    (c) Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (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. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition 42 of this permit.

    (d) Data Exclusion. As provided in III.B. 21-22, valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit. Up to 2 hours of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions.

    [Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-297.520, F.A.C and 40 CFR 60.7].

38. Hours of Operation: Using a component of the gas turbine control system, the permittee shall monitor and record the hours of gas turbine operation. Within five working days following the end of each calendar month, the permittee shall record the total hours of operation (including startups, shutdowns, and malfunctions) for the current month, and the total hours of operation for the current

month plus the preceding 11 months.
[Rule 62-204.070, F.A.C., and Applicant Request]

COMPLIANCE DEMONSTRATIONS

39. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 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.]

40. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits for fuel oil specified in this permit by maintaining records required by 40 CFR 60.334 and 60.335 and the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

41. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of operation and amount of each fuel fired for the combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. All hours of operation shall be included in the demonstration of compliance with the 12-month fuel usage limitations. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

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

43. Excess Emissions Reporting:

    (a) If excess NO_X or visible emissions 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) NSPS Semi-Annual Reports. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. 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 to the Compliance Authority.

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

    (c) SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NOx emissions in excess of the BACT permit standards at Specific Condition 16 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.

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

44. <u>Annual Operating Report</u>: The permittee shall submit an annual report that summarizes the actual fuel usage 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.]

DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
012	One distillate fuel oil storage tank for Combustion Turbine Unit 4 (approximately 1.0 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: As revised October 15, 2003, NSPS Subpart K does not apply to storage vessels which store a liquid with a vapor pressure less than 3.5 kPa.

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 1.0 million gallon distillate fuel oil storage tank designed to provide low sulfur fuel oil to Combustion Turbine Unit 4 or any other units on the site. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

   {Note: Emissions of VOC form this unit are estimated to be less than one ton per year.}

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.]

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT proposal discussed in the Technical Evaluation for this project for the rationale regarding the following BACT determination.

For operation less than 2,500 hours, the following BACT determination applies:

a. NO_x, - 42.0 ppm @ 15% O_2 (75.9 lb/hr) while firing oil.

Continuous compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS and based on a 24-hr block average. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

b. PM/PM_{10} - distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight, and visible emissions $\leq$ 10% opacity, based on a 6-minute average.

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

c. The mass emission rate standards are based on a turbine inlet condition of 41° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

For operation 2,500 hours or greater, the following BACT determination applies:

a. NOx - 5 ppm @ 15% O_2 (8.9 lb/hr) while firing oil.

Compliance with the NO_x standards shall be demonstrated by conducting tests in accordance with EPA Method 7E or Method 20. Tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

d. PM/PM_{10} - distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight, and visible emissions $\leq$ 10% opacity, based on a 6-minute average.

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

b. The mass emission rate standards are based on a turbine inlet condition of 41° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By: Approved By:

Trina L. Vielhauer, Chief
Bureau of Air Regulation

Michael G. Cooke, Director
Division of Air Resources Management

Date

Date

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.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Keys Energy Services
Stock Island Power Plant
Combustion Turbine Unit 4

48-Megawatt Simple Cycle Power Project

Monroe County

DEP File No. 0870007-AC (PSD-FL-348)

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

May 31, 2005

1. APPLICATION INFORMATION

Applicant Name and Address

Keys Energy Services
1001 James Street
Post Office Box 6100
Key West, Florida 33041-6100

Authorized Representative:
Daniel Cassel, Director of Generation

Processing Schedule

- Received Air Construction Permit/PSD application on October 14, 2004;
- Additional information requested November 10, 2004 and February 17, 2005;
- Received additional information on January 18, February 18, and April 13, 2005; and
- Intent to Issue Air Construction/PSD Permit distributed April 22, 2005.

Facility Description and Location

Keys Energy Services (KEYS) operates the Stock Island Power Plant, which is located at 6900 Front Street, Stock Island near Key West in Monroe County. The existing Stock Island Plant consists of two nominal 8.8 MW diesel generators, one nominal 23.5 MW simple cycle combustion turbine, two nominal 19.8 MW simple cycle combustion turbines and miscellaneous unregulated units. The location of the Stock Island Power Plant is shown in Figures 1 and 2.

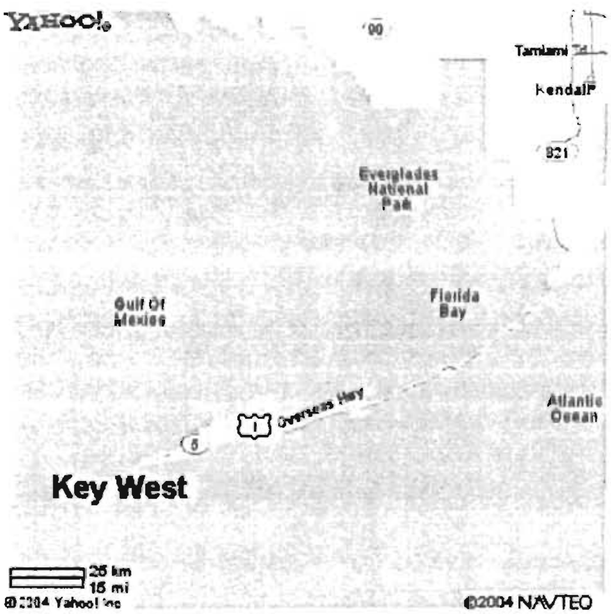


Figure 1. Location of Key West

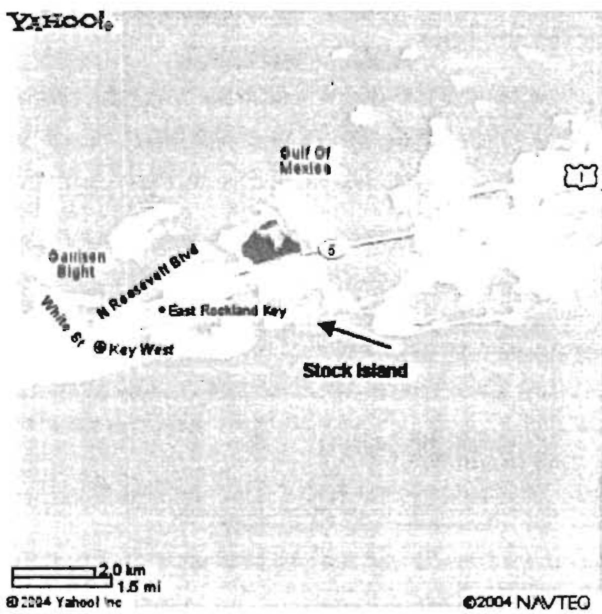


Figure 2. Location of Stock Island

The Stock Island Power Plant is located approximately 90 kilometers southwest from the Class I Everglades National Park.

Regulatory Categories

Title III: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

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

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

PSD: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is a Major Facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The facility is not a steam electrical generating plant and is not subject to the power plant siting provisions of Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a fuel oil-fired simple cycle unit consisting of the following equipment and specifications: one nominal 48 MW General Electric LM6000 PC SPRINT combustion turbine-electrical generator; a nominal 1 million gallon diesel fuel storage tank; a new water tank; and a minimum 60-foot exhaust stack with associated ducting, flow straightening and silencing. Combustion turbines are often referred to as "gas turbines". This refers to use of air (instead of steam) as the operating medium and not firing with natural gas. The less ambiguous term, combustion turbine, will be used in this review. Following are further details.

- Fuel: There is no natural gas infrastructure in extreme South Florida. KEYS proposes to use low sulfur (0.05% Sulfur) distillate oil. The applicant's original request was for 4,420 fuel equivalent hours of operation. The application has since been revised to request 2,500 hours per year of operation.
- Generating Capacity: The proposed combustion turbine has a nominal generating capacity of 48 MW. The actual range is approximately 40 to 50 MW for temperatures between 90 and 40 degrees (°F). This range is related to the higher density and mass flow of the working medium (air) at lower temperatures.
- Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of distillate oil at relatively high temperatures. Emissions of SAM and SO_2 will also be minimized by firing low sulfur distillate oil. NO_X emissions will be reduced by water injection into the combustor.

- Continuous Monitors: The combustion turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitor will be employed for demonstration of continuous compliance with the Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: The following summarizes the exhaust characteristics at 41 °F:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
No. 2 Fuel Oil	433.4 mmBtu/hour	41° F	~814° F	~555,000

Project Description

Refer to Figure 3 below.[1] A combustion turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 5 stage low pressure compressor (LPC) of the GE LM6000 PC SPRINT combustion turbine proposed for this project. The air is further compressed in the 14-stage high pressure compressor (HPC) to a pressure ratio of about 30 times atmospheric pressure. A portion of the compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 30 replaceable fuel nozzles.

The hot combustion gases are then diluted with additional cool air from the compressor and directed to the two-stage high pressure turbine (HPT) section and then the 5-stage low pressure turbine section. The power turbine is directly driven.

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 is discharged at a temperature range of 760 to 860 °F and high excess oxygen and is normally available for additional energy recovery (such as in combined cycle configurations).

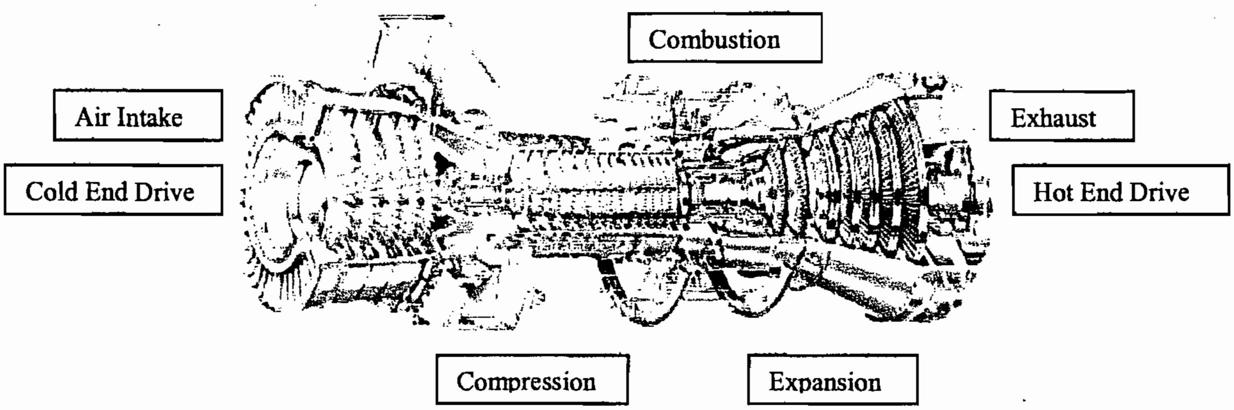


Figure 3. Key Components of the LM 6000 Simple Cycle Combustion Turbine

The particular model selected by the applicant has some very specific features including:

- Water Injection. This feature involves water injection into the combustor for the purpose of NO_X abatement. Greater power production is also realized by the additional mass flow.
- SPRay INTercooling (SPRINT™): This additional feature, known as the Sprint™ System, involves injecting fine water droplets into the LPC and HPC inlet plenums. This provides for better cooling of hot section components and allows higher firing temperatures to be realized in the combustor. This feature increases shaft power by approximately 12 percent (%) at 59 °F and 30% at 90 °F compared to a gas-fired LM 6000 PC practicing water injection.

Further process details are provided in the Draft determination of Best Available Control Technology (BACT) in Section 4.0 below.

Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds. The following table summarizes the applicant's original (and revised) estimate of the annual emissions in tons per year from the proposed project.

Table 1. Applicant's Original (and Revised) Estimated Annual Emissions

Pollutant	Project Emissions TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
CO	34 (21)	100	No
Pb	0.013	0.6	No
NO_X	154 (76)	40	Yes
PM/PM_{10}	110 (31)	15/25	Yes
SO_2	48 (24)	40	Yes (No)
SAM	15 (<7)	7	Yes (No)
VOC	10 (6)	40	No

3. RULE APPLICABILITY

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 Florida Administrative Code.

Chapter	**Description**
62-4	Permitting Requirements
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution

Chapter	Description
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

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.

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
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

Note: Acid rain requirements will be included in the Title V air operation permit.

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined 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. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) listed in Table 62-212.400-2, F.A.C. For each significant pollutant exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project as originally proposed are required for NO_X, SO_2, SAM and PM/PM_{10}. Based on the revised application, determinations are required for NO_X, and PM/PM_{10}

The other part of 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 – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Rule 62-210.200 (definitions), FAC as follows:

"Best Available Control Technology" or "BACT" - 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 energy, environmental and economic impacts, and other costs, 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.

a. *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.*

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

According to Rule 62-212.400(5)(h), FAC, the applicant must at a minimum provide certain information in the application including:

3. *A detailed description of the system of continuous emissions reduction proposed by the facility or modification as BACT, emissions estimates and any other information as necessary to determine that BACT would be applied to the facility or modification;*

According to Rule 62-212.400(6), FAC, in making the BACT determination, the Department shall give consideration to:

1. *Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).*
2. *All scientific, engineering, and technical material and other information available to the Department.*
3. *The emission limiting standards or BACT determinations of any other state.*
4. *The social and economic impact of the application of such technology.*

4.2 NO_X BACT Determination

4.2.1 Nitrogen Oxides Formation

Nitrogen oxides form in the combustion turbine process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

In most 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.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation is depicted in Figure 4 which is from a General Electric discussion on these principles.

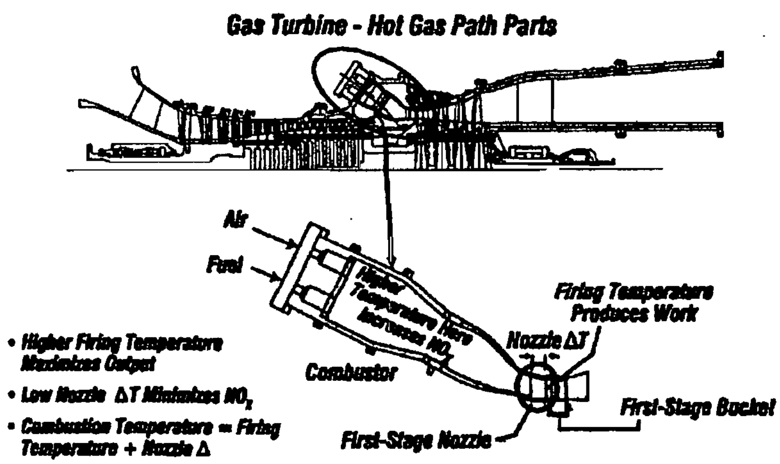


Figure 4 – Relation between Flame Temperature and Firing Temperature

Fuel NO_X is formed when fuels containing bound nitrogen are burned.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 400 ppmvd @15% O_2 for a fuel oil-fired LM 6000 PC SPRINT combustion turbine (200 ppmvd for gas-firing).[2] The proposed NO_X controls will reduce these emissions significantly.

For reference, the New Source Performance Standard (40 CFR 60, Subpart GG) for NO_X emissions from large utility gas turbines such as the GE7FA is approximately 120 ppmvd @15%O_2. This standard, applicable to combustion turbines built after 1977, constitutes the legal floor (absolute maximum NO_X value) in a "Top/Down" BACT determination.

More recently EPA proposed a new standard (40 CFR 60, Subpart KKKK) applicable to combustion turbines that commence construction after February 18, 2005. Proposed Subpart KKKK limits NO_X emissions from large fuel oil-fired combustion turbines to 1.2 pounds NO_X per megawatt-hour (lb/MWH). This equates to approximately 34 ppmvd @15% O_2.[3]

KEYS provided a letter to support their position that KEYS commenced construction on February 18, 2005 such that Subpart KKKK does not apply to the proposed project.[4] Notwithstanding the apparent agreement, the Department must consider the Subpart KKKK proposal in setting a BACT determination for this project, if it is not an applicable requirement.

4.2.2 Descriptions of Available NO_X Controls

Wet Injection

Fuel and air are mixed within traditional combustors and the combustion actually occurs on the boundaries of the flame. This is termed "diffusion flame" combustion. 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 achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 90% for oil firing. GE does not presently guarantee emissions less than 42 ppmvd when firing fuel oil in an LM6000.

Carbon monoxide (CO) and hydrocarbon (HC) 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 Emissions (DLE)

Lean fuel combustion provides a theoretically lower flame temperature. Premixing of the air and fuel prior to entering the combustor 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 GE product for aeroderivative combustion turbines is called Dry Low Emissions (DLE). The features of the early DLE combustion system are shown in Figure 5. In contrast to other low emissions technologies, the lean pre-mix feature of the DLE combustor for aeroderivative engines functions even at low load. As previously mentioned, without DLE or water injection, NO_X would be approximately 200 and 400 ppmvd @15% O_2 on gas and oil respectively.

The first commercial installation of the DLE combustion system was on a 43 MW LM6000 gas fired combustion turbine in the mid-1990's at the Ghent power station in Belgium. It achieved emissions of 16 ppm NO_X, 6 ppm CO and 1 ppm unburnt hydrocarbons.

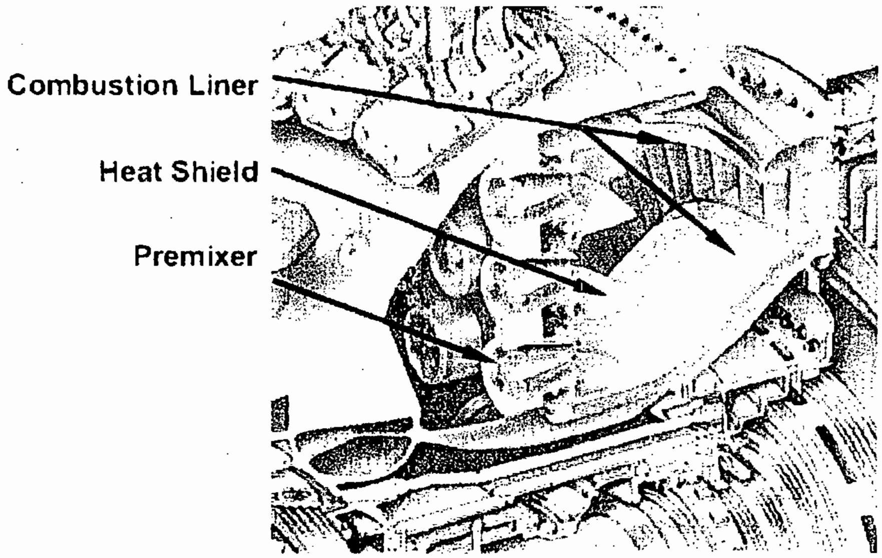


Figure 5 – Dry Low Emissions (DLE) Combustor

Orange Cogen installed two LM6000 PB combustion turbines in the mid-1990's to operate in combined cycle. Initially the units were required to achieve 25 ppmvd NO_X @15% O_2 while firing natural gas with a requirement to reduce emissions to 15 ppmvd several years after startup. Following is the time series developed from the most recent data available from the continuous emission monitoring record submitted quarterly by Orange CoGen to EPA. The values greater than 15 ppmvd are typically short-duration startups that are actually characterized by low mass (lb/hr) emissions during the given hours. The 15 ppmvd NO_x limits for these units are based on 3-hr averaging times, therefore it appears that they are meeting their permitted limits.

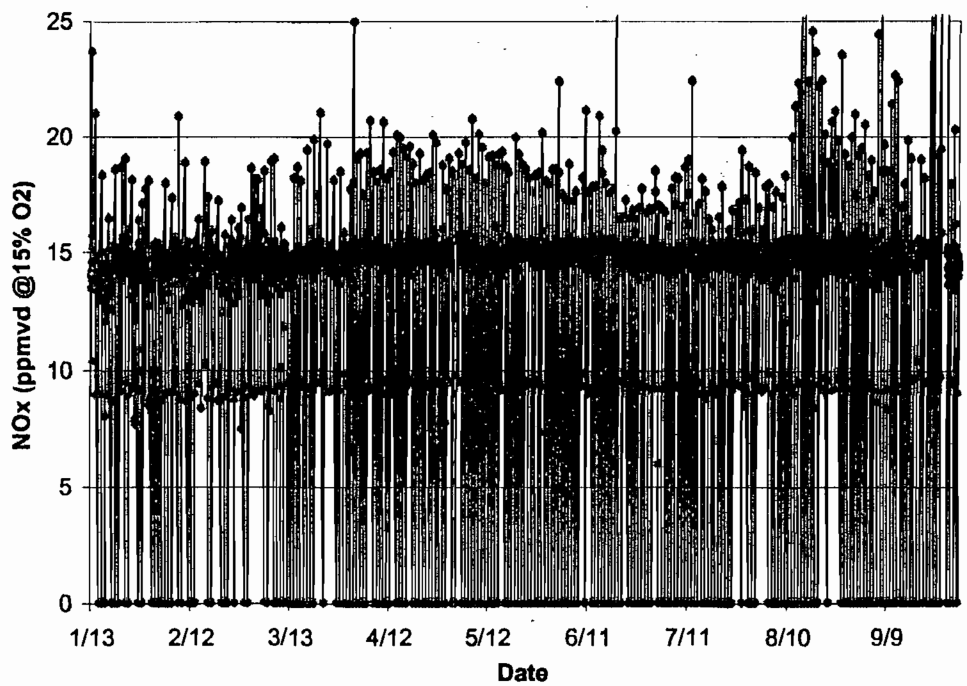


Figure 6 – NO_X Emissions from Orange CoGen LM6000 PB Gas-Fired Unit 1 (2004)

The DLE arrangement installed at Orange CoGen is not available on newer versions of LM 6000 combustion turbine. There is a newer version called DLE-II technology that is available on newer LM6000 PC and LM6000 PC SPRINT combustion turbines. According to GE sales and technical experts, the DLE-II is available with a 15 ppmvd guarantee while operating on natural gas.[5]

The DLE-II was designed to operate in conjunction with the higher power features of the newer versions of the LM 6000 PC and PC SPRINT. This was made possible by dispensing of a shroud in the combustion area that previously required cooling. The lower cooling requirement makes it possible to divert more air from the compressor to make a leaner air-fuel mixture for combustion.

DLE and DLN technologies are technically possible for oil-fired units. However they are more expensive and it is more difficult to reach the values achievable by DLN or DLE when using gas. According to the Siemens-Westinghouse website, their 45 MW SGT-800 combustion turbine (formerly ABB GTX100) with their 3rd generation DLE combustor can meet 25 ppmvd @15% O_2 when burning fuel oil.[6] It is not certain whether this is accomplished by wet injection or by the DLE feature.

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.[7] 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™.[8] 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.[9] By now, 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.[10] 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 yet available for fuel oil-fired combustion turbines of the size of an LM 6000 PC SPRINT.

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.

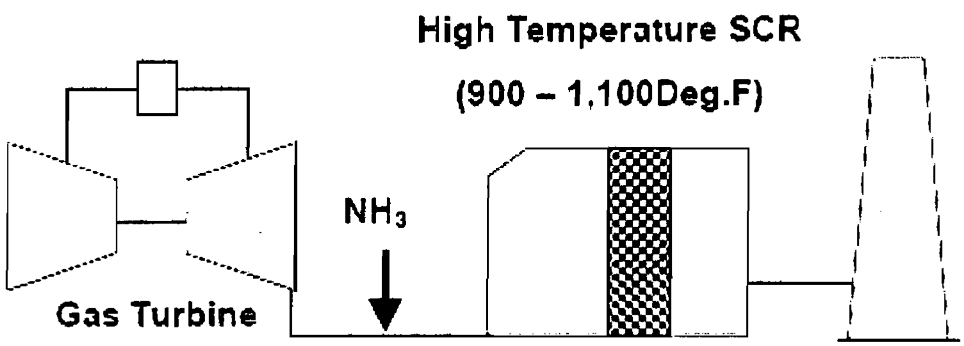


Figure 7 – High Temperature SCR Configuration for Simple Cycle Combustion Turbine

SCR technology has progressed considerably over the last decade. Zeolite catalyst was developed for high temperature applications. Such catalyst provided by Engelhard was involved in a failed application at the oil-fired simple cycle PREPA Cambalache project in Puerto Rico in the late 1990's. The permitted limit while firing fuel oil in the three nominal 83 MW ABB GT-11N was 9 ppmvd.[11]

There has been much debate regarding the reasons for the failure ranging from the use of fuel oil, its sulfur content of 0.15%, the nature of high temperature applications, water injection, the catalyst, etc. EPA allowed removal of the catalyst from the simple cycle units and installation of Low NO_X burners on some boilers located at the same facility to abate the NO_X increase. It is important to note that the permit application was submitted 11 years ago and improvements have since been made in high temperature SCR catalysts.

All of the catalyst suppliers presently offer formulations and strategies for applications for the moderate temperature range (760 – 860 °F) of SCR applications suitable for the LM6000 PC SPRINT. Hitachi offers a catalyst with a TiO_2 base and tungsten (WO_3) that Hitachi claims outperformed zeolite catalyst in accelerated durability tests.[12] The peak activity temperature (842 °F) for Hitachi's catalyst is virtually equal to the exhaust temperatures expected from the LM6000 PC SPRINT at full load. This temperature is less than experienced by the catalyst at the PREPA Plant (824 to 1014 °F).

The following figure reflects Hitachi's view of its high temperature TiO_2/WO_3 formulation compared with conventional low/middle temperature V catalyst and high temperature zeolite catalyst.

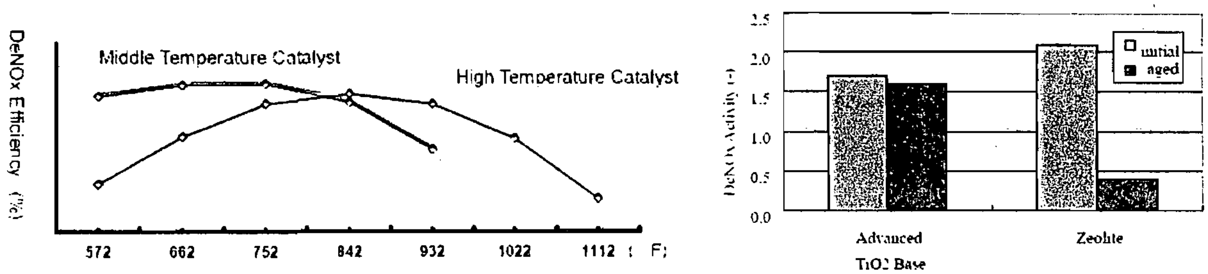


Figure 8 – High Temp TiO_2/WO_3 versus Mid-Temp V and High Temp Zeolite Catalysts

If this information is accurate, it certainly provides reason to believe that a possible cause is inherently shorter lifetime for zeolite formulations. According to Hitachi the accelerated zeolite deterioration observed during its durability tests was caused by the water concentration in exhaust gas that impacted the crystalline structure. Moisture in the flue gas would be the case for all fuel applications, especially when firing natural gas.

One implication of Hitachi's findings is that gas firing (had it been available at PREPA Cambalache) could have caused even faster deterioration of the zeolite catalyst than observed. Therefore the past problems with hot SCR and fuel oil firing are more likely related to the catalyst formulation than to the use of fuel oil.

One possible strategy is to cool the exhaust gas to match the peak activity point of the less expensive medium temperature V catalyst at about 700 °F. This can be done using tempering air supplied from a cooling air skid. This options allows use of more familiar catalyst formulations without ammonia oxidation.

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.

Fortunately sulfur is not a problem for the catalyst in high temperature and relatively low sulfur fuel applications (natural gas or distillate fuel oil) because the ammonium sulfate, bisulfate, sulfite deposits burn off at the high operating temperatures.

There are several examples of <u>conventional</u> SCR systems operating in Florida including:

- Kissimmee Utilities Authority Unit 3. 3.5 ppmvd NO_X on gas and 12 ppmvd on fuel oil.
- Progress Energy Hines Block 2. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- JEA Brandy Branch. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- TECO Bayside – seven combustion turbines. 3.5 ppmvd on gas.
- FP&L Manatee Unit 3. 2.5 ppmvd on gas and 10 ppmvd on fuel oil
- FP&L Martin Unit 8. 2.5 ppmvd on gas and 10 ppmvd on fuel oil.

There are several other approved projects now under construction in Florida that require conventional SCR systems. Most recently, DEP issued a permit for Turkey Point Unit 5 with NO_X limits of 2.0 ppmvd on gas and 8.0 ppmvd on fuel oil.

SCR has been installed in several dozen simple cycle gas-fired LM6000 combustion turbines and in a few fuel oil-fired units. Typical emissions limits are on the order of 2.5 to 5 ppmvd. SCR was also specified for the recently approved LM6000 PC SPRINT units to be installed at the City of Tallahassee Hopkins Plant. The guaranteed NO_X limits are 5 ppmvd whether burning gas or fuel oil.

SCONO$_X$™

This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power is 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 but in the exhaust of an LM6000 PC SPRINT combustion turbine.

SCONO$_X$™ systems were installed at seven sites ranging in capacity from 5 to 43 MW.[13] None were installed at large facilities.

SCONO$_X$™ technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx™ has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, SCONO$_X$™ 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.

The need for more cooling air (compared to SCR catalysts) to achieve the necessary temperature operating range and the requirement for natural gas or hydrogen for regeneration of the catalyst makes SCONO$_X$™ infeasible for this project.

4.2.3 Applicant's Original NO_X BACT Proposal

The applicant originally proposed a BACT NO_X limit of 42 ppmvd @15% O_2 while operating 7000 hours per year and limiting annual fuel use to the equivalent of 4,420 hours per year. KEYS proposes to meet the proposed BACT emission limit by water injection.

The reader is referred to the KEYS application on-file with the Department and available on-line at the site given at the end of this review. In summary, the KEYS asserts that SCR is not technically or economically feasible for the following (paraphrased) reasons:

- SCR catalyst failed on an oil-fired simple cycle application at the PREPA project.
- There are insufficient hours of operation at other existing installations to conclude that SCR is reliable on oil-fired simple cycle units.
- The catalyst will have to be replaced every year.
- Any downtime is virtually unacceptable.
- The area is basically isolated and there are few power alternatives for the area especially if storms make power unavailable from the mainland.
- The marine environment and remote location drive up materials and construction costs.
- The overall cost per ton of NO_X removed is too high.
- The cost analysis submitted by the City of Tallahassee (who proposed SCR) contains errors.

4.2.4 Department's Draft NO_X BACT Determinations

A) Recent Test Data

Table 2 contains some information from a recent report prepared by the California Air Resources Board (CARB) to the Legislature regarding control technologies that reduce NOx emissions from gas-fired power plants.[14] All of the results appear to be on gas-fired LM 6000 combustion turbines. In all reported tests, NO_X emissions were less than 5 ppmvd. All but a few ammonia measurements were equally low. The one result listed in Table 3 for the New York Port Authority (NYPA) Hellgate plant is probably representative of the 11 new LM 6000 SPRINT combustion turbines known to be operated by the NYPA. According to a report prepared in 2003 for the NYPA, all of their units had no problems complying with the very strict NO_X limit of 2.5 ppmvd @15% O_2 during steady-state conditions.[15] However, during startup and shutdown these units often exceeded permit limits. This issue has since been resolved through a Consent Order and new permit limits for startup and shutdown periods.

Table 2. Test Results for LM 6000 Simple Cycle Combustion Turbine Projects

Project Location	Date	NO_X / NH_3 (ppmvd @ 15% O_2)	Comments
NYPA, Hellgate, NY	2001	1.7 – 2.2 / 3.4 - 14	Water Injection & SCR
Calpine Lambie, CA	1/2003	2.5 / 1.5	Water Injection & SCR
Calpine Creed, CA	1/2003	1.5 / 0.8	Water Injection & SCR
Calpine Goose, CA	1/2003	2.4 / 0.4	Water Injection & SCR
N. Cal., Lodi, CA	7/2000	2.8 / 25	Steam Injection & SCR
Wellhead, Huron, CA	3/20/2002	2.7 / 0.4	Water Injection & SCR
Gilroy Energy, CA	2002	3.3 – 3.6 / 0.9 – 1.5	Water or DLE & SCR
Palm Springs, CA	2001	3.8 – 4.5 / 2.2 – 4.2	Steam or Water & SCR
San Diego, CA	2001/02	3.4 – 4.6 / 1.3 - 37	Water Injection & SCR

B) Recent Determinations

Table 3 includes some recent BACT determinations in Florida and other states for LM6000 series combustion turbines as well as some Lowest Achievable Emission Rate determinations. All specify SCR. Some of the information is from the previously mentioned CARB report to the Legislature.

All of the listed determinations are for NO_X emission limits less than or equal to 5 ppmvd @15% O_2. Most are approximately 2.5 ppmvd @15% O_2. In 1999, CARB issued guidance establishing a maximum value of 5 ppmvd for Power Plant Siting and BACT in California for simple cycle units.[16].

Additional information was located in the report prepared in 2003 for the New York Port Authority (NYPA) mentioned above. The purpose of the report was to review the performance of the numerous LM6000 PC SPRINT installations recently installed by NYPA. The permitted limits were issued at a time when there was much less information about actual performance of these units than there is today.

Based on the list, the "Top" technology in a "Top/Down" determination is 2.0 ppmvd for natural gas fired units and approximately 5.0 ppmvd for fuel oil-fired units. The NO_X BACT limit proposal submitted by KEYS is significantly greater than the top technology. It cannot be accepted without showing that technical or economic considerations make significantly lower values infeasible.

Table 3. Recent NO_X Standards for LM 6000 Simple Cycle Combustion Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2 and Fuel	Comments
Tallahassee, FL	100	5 – NG/fuel oil (24-hr)	2xLM 6000 PC SPRINT (NH_3=10)
W. Springfield, MA	84	3.5 /6.0 – NG/Oil (1-hr)	2x42 MW LM6000 (NH_3 = 7.0/10)
Lowell, MA	96	2.0 – NG (1-hr)	2x48 MW LM6000 (NH_3 =2.0)
Wallingford, CT	225	2.5 – NG (1-hr)	5x45 MW LM6000 (NH_3 = 6.0)
Shoreham, L. Island	~95	9 – fuel oil (1-hr)	2xLM 6000 (NH_3 = 10)
NYPA Hellgate	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA Harlem River	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA N. 1st St.	47	2.5 – NG (1-hr)	1x47 MW LM6000 SPRINT CTs
NYPA 23rd St/3rd Ave	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA Vernon Blvd.	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA Pouch Term.	47	2.5 – NG (1-hr)	1x47 MW LM6000 SPRINT CTs
NYPA Brentwood	47	2.5 – NG (1-hr)	1x47 MW LM6000 SPRINT CTs
Calpine Lambie, CA	50	2.5 – NG (3-hr)	1x49.9 MW LM6000 PC SPRINT
Calpine Creed, CA	50	2.5 – NG (3-hr)	1x49.9 MW LM6000 PC SPRINT
Calpine Goose, CA	50	2.5 – NG (3-hr)	1x49.9 MW LM6000 PC SPRINT

Table 3 (Cont.) Recent NO_X Standards for LM 6000 Simple Cycle Combustion Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2 and Fuel	Comments
Modesto Ripon, CA	95	2.5 – NG (3-hr)	2x47.5 MW LM6000 PC SPRINT
Lodi Energy, CA	50	3.0 – NG (3-hr)	1x49.6 MW LM6000 PC SPRINT
Herndon, CA	50	3.0 – NG (3-hr)	1x49.6 MW LM6000 PC SPRINT
N. Cal., Lodi, CA	49	3.0 – NG (3-hr)	1x49 MW LM6000 PC SPRINT
Wellhead, Huron, CA	45	3.5 – NG (3-hr)	1x45.4 MW LM6000 CTs
E.I. Colton, CA	48	3.5 – NG (3-hr)	1x48 MW LM6000 SPRINT
Gilroy Energy, CA	135	5 – NG (1-hr)	3x45 MW LM6000 PC
Palm Springs, CA	135	5 – NG (3-hr)	3x45 MW LM6000 SPRINT
Carson Energy, CA	42	5 – NG (3-hr)	1x42 MW LM6000 (started 1995)

It is noted that most if not all of the units listed in Tables 2 and 3 employ water or steam injection instead of DLE in conjunction with SCR. This means that gas-fired units are similar to the fuel oil-fired LM 6000 combustion turbines in regard to the employment of wet injection techniques and the purpose of SCR for further control.

i) Results for Shoreham Oil Fired LM 6000 Units

Long Island Power Authority (LIPA) supplies the fuel for, and Pennsylvania Power & Light (PPL) operates, the Shoreham Plant on Long Island, New York. The plant is one of several small installations sited at key locations throughout Long Island to meet escalating demand. There are two fuel oil-fired LM6000 combustion turbines at the Shoreham Plant.

For reference, Long Island is also characterized by a marine environment. The weather can be very cold and severe in the winter requiring heating of fuel or measures to insure the temperature of SCR catalyst is maintained at an optimal value.

The permit issued for the Shoreham Plant is a non-PSD permit with a short-term NO_X limit of 9 ppmvd @15% O_2 on a 1-hour basis and an annual limit of 22.5 tons between the two units. There is an NH_3 limit of 10 ppmvd @15% O_2 on a 1-hour basis. The permit requires both NO_X and NH_3 continuous emission monitoring systems (CEMS). NO_X emissions are controlled by water injection and SCR. Each unit has a 110-foot stack. The units started up in June 2002.

The Department downloaded 2003 CEMS NO_X data submitted by PPL from the EPA Air Markets Website. They operate in intermittent duty and never operate an entire 24-hour period in a day.

Figure 9 is the time series for August 2003 for both units. It includes all valid hours during which at least 0.25 hours of data were recorded. For the most part, emissions were in the range of 3 to 8 ppmvd @15% O_2. The peak value observed was 23 ppmvd and occurred during an hour that included a startup and only 0.32 hours of operation. Only 7.5 pounds of NO_X were emitted that entire hour.

According to PPL's filings with the Securities and Exchange Commission, the SCR system was provided by Deltak, L.L.C. The Department does not have information regarding the catalyst supplier used by Deltak.

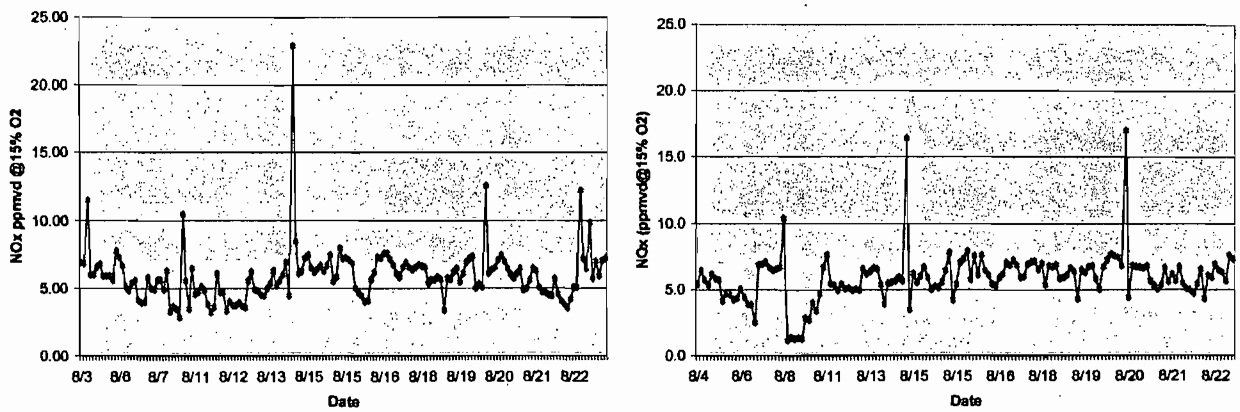


Figure 9 – NO_X Emissions - PPL Shoreham LM6000 Oil-Fired CTG-1&2 (August 2003)

ii) West Springfield Gas and Oil-Fired Project

The Consolidated Edison West Springfield Redevelopment Project is located in Massachusetts. It consists of two 42 MW GE LM6000 combustion turbines with water injection and SCR for NO_X control. Initially the project was permitted to fire natural gas only.

The initial BACT NO_X limit for the West Springfield Project (final approval June 9' 2003) was 2.5 ppmvd @15% O_2 and ammonia slip of 2.5 ppmvd NH_3 @15% O_2. The new units were initially not able to achieve the specified BACT limits during transient or steady-state conditions. Since that time, a new limit of 3.5 ppmvd @15% O_2 while burning gas has been set.

Massachusetts DEP approved use of ultralow sulfur fuel oil (< 0.0030 % sulfur) in November 2003 and allowed an increase in use of gas and fuel oil in July 2004.

Table 4 is a listing of the permit conditions applicable to the West Springfield Project. Table 5 summarizes the fuel use limitations for the two units.[17] Table 6 is a summary of operating hours and NO_X emissions since the units started operation in 2002 until the end of the third quarter of 2004. The information was accessed from the EPA Air Markets Website. The total NO_X emissions are 20.5 tons combined for the two units since they started up in 2002.

Table 4. Emissions Limits for two LM6000 Combustion Turbines at W. Springfield

Pollutant	Natural Gas		Oil (Ultra Low Sulfur)		Mass Emission Limits
	ppmvd @15% O_2	lb/hr (each CTG)	ppmvd @15% O_2	lb/hr (each CTG)	tpy (3) (both CTGs combined)
PM(2)	n/a	4.5	n/a	11.3	14.7
SO_2(4)	0.4	0.9	0.7	1.5	2.9
NO_X	3.5	5.9	6.0	10.8	19.3
CO	5.0(5) / 10.0(6)	4.3	5.0(5) / 10.0(6)	1.0	27.7
VOC	2.0	1.1	12.0	6.4	7.4
SAM	n/a	0.15	n/a	0.2	0.3
NH_3	7.0	4.4	10	6.2	10.6 (7)
Opacity	≤ 5 percent(8)		≤ 20percent(8)		

Table 5. Fuel Use Limits for two LM6000 Combustion Turbines at W. Springfield

Combustion Units	Natural Gas		Oil (Ultra Low Sulfur)	
	cubic feet/mon (1)	cubic feet/yr (2)	gallons/mon (1)	gallons/year (2)
CT-1 & CT-2	344,174,400	3,019,640,000	2,455,731 (3)	5,828,607 (3)

(1) Calendar Month
(2) Based on a rolling 12-month total
(3) Assuming natural gas heating value of 1000 Btu/ft^3 and oil heating value of 140,000 Btu/gallon.
(3) For every gallon of oil fired, the natural gas allowance (per calendar month or per rolling 12-month total) shall be reduced by 359.4 cubic feet.

Table 6. Hours and NO_X Emissions from W. Springfield LM6000 CTs (2002-2004)

Unit/year	Hours	Heat Input	NO_X (lb/mmBtu)	NO_X (TPY)
CTG1/2004	291	87540	0.09	1.70
CTG2/2004	209	64180	0.11	1.40
CTG1/2003	674	211206	0.04	1.90
CTG2/2003	388	112371	0.11	1.90
CTG1/2002	652	228565	0.06	7.10
CTG2/2002	747	252897	0.05	6.50
Total/2002-04	**2961**	**956759**	**0.04**	**20.50**

Figure 10 is a time series for the dual fuel fired units, Units 1and 2, at West Springfield. The graph includes only the hours during which fuel oil was fired in 2004. Substantial firing after mid-year was primarily with natural gas due to the higher seasonal cost of fuel oil. The graphed values represent only discrete hours that are not necessarily contiguous. They do not include data when the unit operated for 15 minutes or less. This avoided inclusion of excluded data as "zeros". The high values in January apparently occurred during hours that contained both a startup and a shutdowns. The others occurred at very low load (< 8 MW). Although the concentrations appear to be high, the impact on annual emissions is minimal.

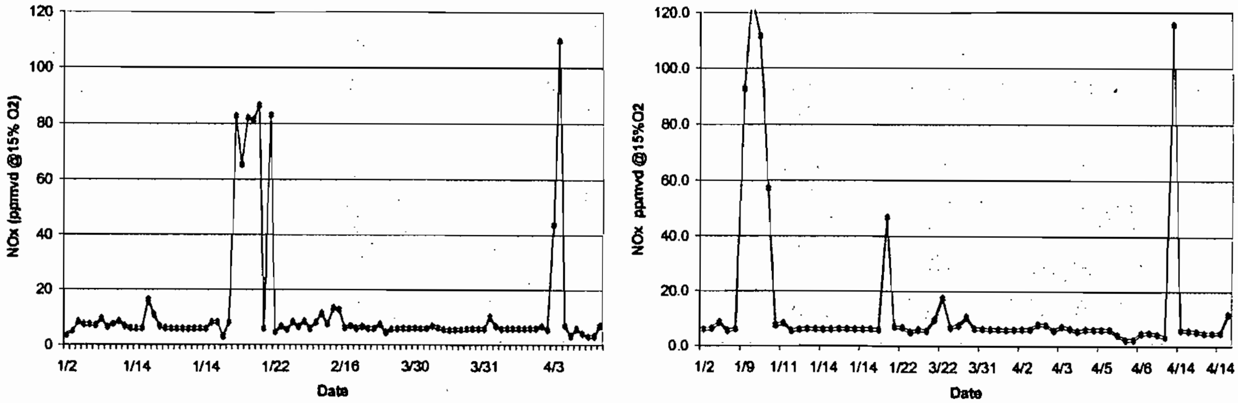


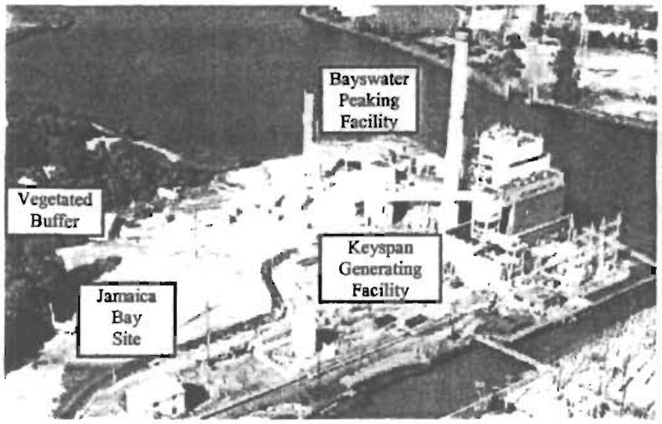
Figure 10 – NO_X Emissions - W. Springfield LM6000 Dual Fuel Units 1&2 (Oil, 2004)

The SCR systems were provided by Peerless and used Haldor Topsoe catalyst. The precise catalyst formulation is not yet known by the Department. It is certainly not zeolite and is believed to be a titanium and tungsten formulation. A Department representative visited with representatives of Haldor Topsoe at the 2004 Power Gen Conference.[18] They showed the Department representative startup curves for one of the West Springfield combustion turbines while firing oil. According to the curves, startup was accomplished within 10 minutes after which NO_X emissions were less than 5 ppmvd and at times approached 2 ppmvd @15% O_2.

Department personnel contacted the Massachusetts DEP. Their representatives stated that the West Springfield Project has not had any problems meeting the new limits of 6 ppmvd while burning natural gas and 10 ppmvd @15% O_2 while burning fuel oil.[19] The Department also contacted a representative of Consolidated Edison who said they have had no problems so far and there has been no sign of catalyst degradation.[20]

iii) FPL Bayswater - Pratt& Whitney Oil and Gas Fired Projects

Bayswater consists of two projects built by FPL in the area of Far Rockaway, Queens, New York. It is adjacent to the existing Keyspan Generating Facility. The first of the two FPL projects was called Bayswater and the second was called Jamaica Bay. They are treated as a single facility called Bayswater under the EPA Acid Rain Program. Following is a picture of the two FPL projects and the separate Keyspan facility.



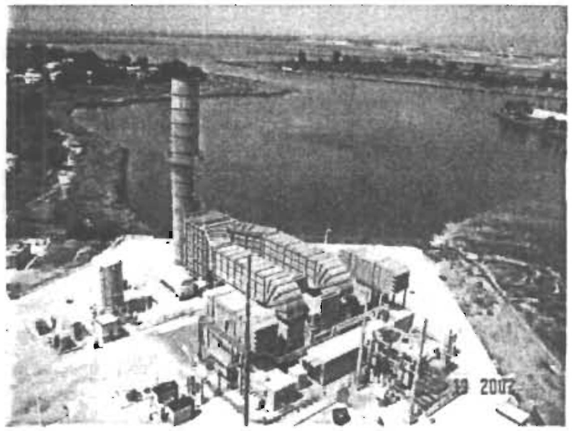


Figure 11 – FPL Bayswater Projects. Two Dual Fuel Pratt & Whitney Swift-Pac Sets

The Bayswater facility is comprised of two simple cycle dual fuel 54 MW Pratt & Whitney FT-8 Swift-Pacs. Each Swift-Pac consists of two small combustion turbines, "pantleg" ducting, a single electrical generator and stack. The primary fuel for the Bayswater Project is natural gas. The primary fuel for the Jamaica Bay project is fuel oil.

According to the Project Environmental Assessment, the NO_X emission limits proposed for the Jamaica Bay project (the second of the two) were 2.5 ppmvd and 6.0 ppmvd @15% O_2 for gas and oil respectively.[21] The annual emissions through the third quarter of 2004 for both projects are listed in the following table. The information source is the EPA Markets Website.

Table 7. Hours and NO_X Emissions from FPL Bayswater P&W CTs (2002-2004)

Unit/year	Hours	Heat Input	NO_X (lb/mmBtu)	NO_X (TPY)
Bayswater/2004	1,567	889,976	0.02	7.2
Jamaica Bay/2004	343	177,743	0.05	2.4
Bayswater/2004	1,210	675,991	0.05	14.5
Jamaica Bay/2003	517	286,020	0.07	7.1
Bayswater/2002	708	377,376	0.07	12.8
Total/2002-04	**4345**	**2,407,106**	**0.037**	**44.0**

Figure 12 is a time series for August 2004 for the two Bayswater units (i.e. Bayswater and Jamaica Bay). The graphed values represent all hours for which data were reported including startups and shutdowns. All high values occurred during partial hours of operations were related to startup. For the most part emissions were typically 5 ppmvd for the fuel oil-fired Jamaica Bay Unit (graph on left) and 2 ppmvd for the Bayswater Unit during steady state.

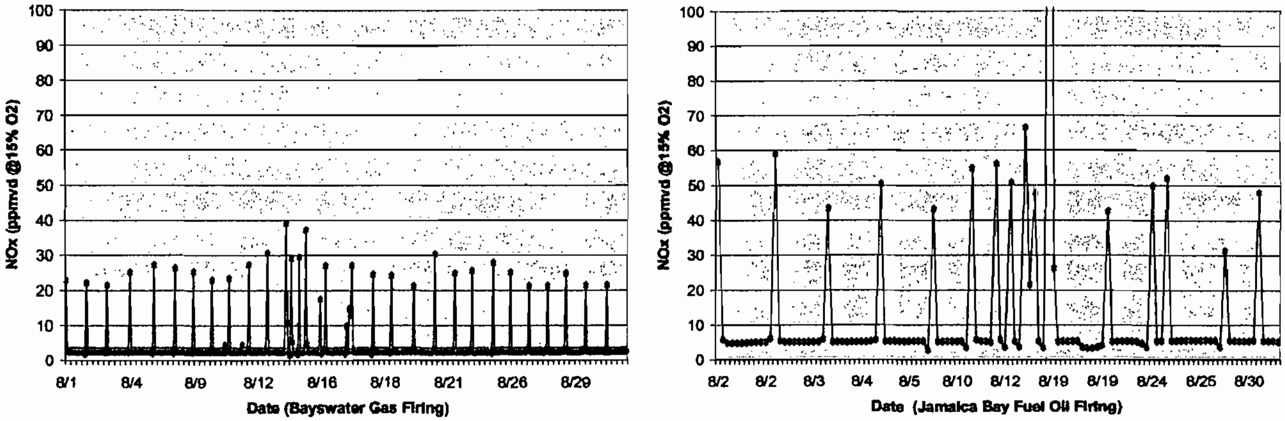


Figure 12 – NO_X Emissions from FPL Bayswater Gas and Oil-Fired Units (August, 2004)

The two plots are similar in that each indicates higher emissions during startup, representative of the water injection targets of 42 ppmvd for oil firing and 25 ppmvd for gas firing prior to enabling of the SCR systems. Although the concentrations are relatively high during each startup hour (usually a fraction of an hour), mass emissions are actually low.

Department personnel contacted a representative of Envirokinetics who supplied the SCR systems for both projects.[22] The gas-fired Bayswater project that started up in 2002 used a catalyst formulation known as Engelhard VNX-HT. According to Engelhard, it is designed for a temperature range of 600 to 875 °F with an optimum range between 800 and 850 °F. The catalyst has a relatively low vanadium (V) content and high titanium oxide (TiO_2). This is consistent with the nominal 840 °F exhaust temperature of the P&W Swift-Pac characteristics.

The fuel oil-fired Jamaica Bay project that started up in 2003 used a catalyst formulation known as Haldor-Topsoe DNX. Topsoe's formulations are typically tungsten (W) and TiO_2. This is consistent with the previous discussion regarding the Hitachi catalyst and operation at moderate to high temperature.

Both catalysts perform well based on the graphs shown above. In its research, the Department also found that the Haldor-Topsoe product has lower pressure drop characteristics, which means less power is lost.[23]

Department representatives contacted an operations expert of FPL Energy at the Bayswaters facility. He confirmed the details provided by Envirokinetics and Haldor-Topsoe. Among the key points were that the units are 98-99% reliable. Both comply with their respective NO_X emission standards.

The only concern expressed by the FPL representative about the use of SCR with fuel oil is an effect on the continuous emission monitoring system (CEMS) for ammonia. Apparently, small amounts of carbon build up in the sampling system. It is theorized that the carbon buildup causes adsorption of ammonia which can be subsequently released. The observation is that NH_3 levels appear to oscillate. No effect is seen on NO_X removal or the functioning of the catalyst. FPL is experimenting with changes to the NH_3 sampling system.

The Department concludes that this side-by-side comparison constitutes a good real-world experimental comparison of SCR for simple cycle gas firing with SCR for fuel oil-firing. Most factors other than the fuels and their delivery systems are equal. The results suggest that problems at previous simple cycle installations had less to do with inherent characteristics of fuel oil than they have to do with catalyst formulation.

iv) Hawkeye Greenport Long Island Oil-fired Project and Freeport Energy Gas-fired Project

In additional information submitted by KEYS, reference was made to "the failure of the catalyst at the Greenport Facility" on the far east side of Long Island. The Hawkeye (formerly Global) Greenport facility is a fuel oil-fired 50 MW P&W Swift-Pac Combustion Turbine set. The unit started up in 2003.

By its letter dated February 16, 2005 KEYS referred the Department to Mr. Tom Turner, President of Turner Envirologic, and the supplier of the SCR system installed at Hawkeye. Department representatives contacted Mr. Turner. He described the original catalyst as a zeolite formulation consistent with the failed product at the oil-fired PREPA simple cycle project. The zeolite catalyst at Hawkeye was replaced with a TiO_2 and W formulation consistent with the successful product at the FPL Bayswater units.

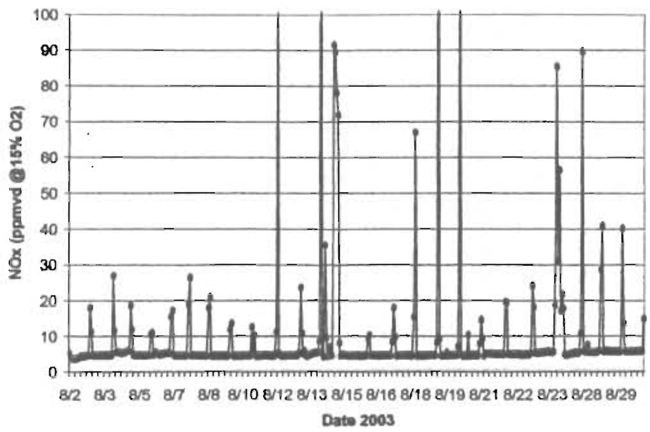
Mr. Turner added that his firm also supplied the SCR system on the 50 MW Freeport Energy facility that consists of a gas-fired GE LM6000 SPRINT combustion turbine. The same zeolite catalyst formulation was also replaced with the TiO_2 and W formulation previously described. His firm also oversaw the replacement of the catalyst at the gas-fired LM6000 for the City of Burbank with the Haldor-Topsoe formulation. He also supplied the SCR system for the 100 MW dual-fuel Larkspur, San Diego project that incorporates LM 6000 combustion turbines.

The following table is a summary of the operation of the Hawkeye Greenport oil-fired unit since its startup. The total annual and average NO_X emissions that include startups are low.

Table 8. Hours and NO_X Emissions from Hawkeye Greenport P&W CT (2003-2004)

Unit/year	Hours	Heat Input	NO_X (lb/mmBtu)	NO_X (TPY)
Hawkeye (Oil)/2004	699	333,809	0.04	4.3
Hawkeye (Oil)/2003	773	363,120	0.05	4.5
Total/2003-04	**1,472**	**696,929**	**0.026**	**8.9**

The lb/mmBtu entries for 2003 and 2004 based on the average of the individual hourly measurements. However the lb/mmBtu entry for the totals is less because the data are weighted by production. Basically the higher 2003 and 2004 values include partial hours such as startups that are characterized by greater lb/mmBtu (and ppmvd) values but lower lb/hr values. The time series for emissions from the Hawkeye Greenport oil-fired facility during August 2003 and August 2004 are displayed are displayed in Figure 13.



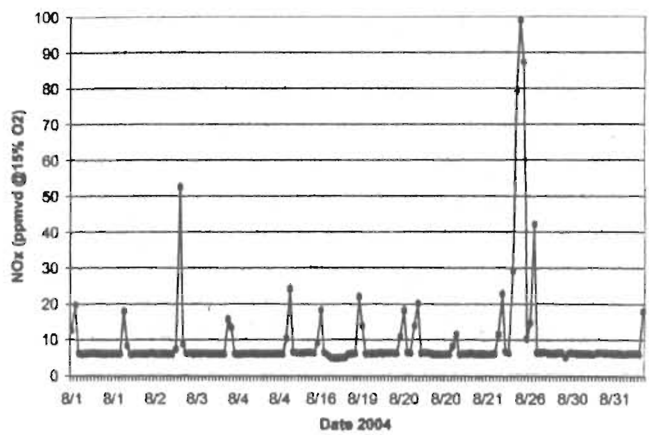
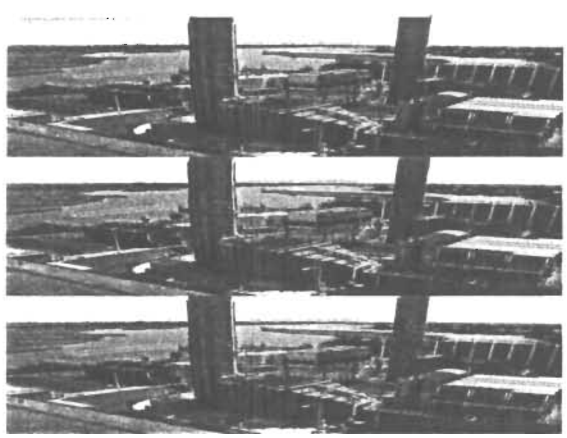


Figure 13 – NO_X Emissions - Hawkeye Greenport Oil-fired Units (Aug., 2003, 2004)

The difference between the two graphs is that startup emissions tended to be greater in 2003 than 2004. While the Department does not have the details regarding the alleged failure, it appears that steady-state emissions have been low. It is possible that the problems were related to very restrictive startup emission limits or problems maintaining low ammonia emissions.

As mentioned, Mr. Turner said that the Freeport gas-fired experienced similar problems. There are two LM6000 SPRINT units located at the site. One is owned by Freeport Energy. The other is owned by a merchant company affiliated with PPL. Following is the time series for the unit designated as Freeport for most recent months given in the EPA Air Markets Website.



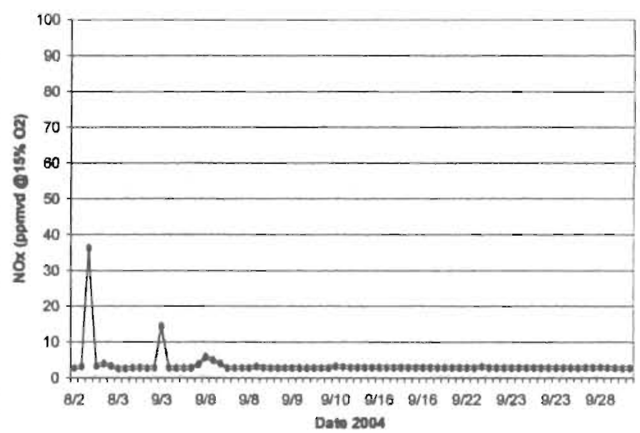


Figure 13 – Photo and NO_X Emissions – Freeport Energy Gas-fired Unit (Aug/Sept., 2004)

Emissions from the Freeport gas-fired LM6000 unit are clearly very low and meet the 2.5 ppmvd limits except during startup. In any case, the compelling facts are: both the fuel oil-fired and gas-fired unit referenced by Mr. Turner operate well now. The zeolite catalyst in each has been replaced with a formulation more appropriate for the application. The source, Mr. Turner, cited by KEYS does not believe fuel oil-firing was the cause of the alleged failures. In fact, he stated that the cause of the alleged failures was related to the zeolite catalyst for the particular conditions.

Mr. Turner's statements and the Department's conclusions are consistent with the observations by Hitachi about zeolite catalyst, the PREPA failure using zeolite catalyst, and the FPL Bayswater success using the Cormetech low V/TiO_2 and the Haldor-Topsoe TiO2/W formulations. This is not to suggest that zeolite catalysts are doomed to failure. They just need to be reformulated or cooled or used within the correct applications.

v) City of Tallahassee Fuel Oil and Gas-fired Project

The Department recently determined that SCR is cost-effective for a project by the City of Tallahassee (COT) to install two GE LM6000 PC SPRINT gas and fuel oil-fired combustion turbines. The project was permitted to operate 4,000 hours per year while firing fuel oil and 1,600 hours per year while firing natural gas. The BACT emission limit was determined to be 5 ppmvd @15% O_2 whether gas or fuel oil is used.

KEYS reviewed the application and determination for the COT project and claim numerous errors and flaws. The Department notes that the calculations submitted by COT actually represent "marginal" rather than average cost-effectiveness.

The higher marginal cost-effectiveness values (adding SCR to wet injection) would not change the conclusion. Conducting the analysis assuming baseline control to the NSPS value of approximately 110 ppmvd would also be cost-effective.

C. Cost-effectiveness of NO_X Control

Cost-effective values for the KEYS project were originally submitted in a response to a request by the Department for additional information and with the intent of the unit to be operated almost continually for a total of 4,420 fuel equivalent hours. The Department is in disagreement with KEYS with respect to several items included in this original analysis. The following summarizes the major issues of which the Department is in disagreement.

The Department believes that the KEYS total direct costs estimate (weighted from several bids) is somewhat high because of a bid by GE Energy. The GE bid is likely high due to the fact that this company would have used one of the other suppliers, added an additional charge, and not actually supply the same duration guarantee as the underlying bidders.

Cost-effective values supplied by KEYS are also high because of the inclusion of a 20 percent ($626,000) contingency. EPA believes the contingency should be 3%. In any event, since KEYS has decided to use GE as the overall project supplier, the contingency for the SCR system will be absorbed into the total LM6000 project contingency that is surely less than 20%.

The cost of an annual catalyst change ($383,000) is unreasonable because the bidders will guarantee the catalyst lifetime or pay a pro-rated replacement cost. The annual replacement assumption alone adds about $2,000 of cost per ton of NO_X removed.

The claimed cost ($353,000) of power lost during an annual catalyst change-out is also unreasonable. EPA excluded this term in its own review. Even if such costs were allowed, correction for a change-out every three years would lower the cost-effectiveness value by nearly another $2,000 per ton. Additionally, the Department believes that the change would not take one week, but rather 2 to 4 days. Most likely such a change out can be timed to other scheduled outage that occur in terms of several years rather than every year.

An interest rate of 7% is assumed. While EPA uses the concept of the "social" interest rate, it is not a practical term. The actual interest rate for a non-taxable utility for bonds maturing over a period of 15 years is lower. However at this time, the difference between the social interest rate and the real interest rate for FMPA is not great. It is noted that claims to use social interest rates can establish a precedent that makes it difficult to use the real interest rates on subsequent projects when the rates increase.

Rather than point out other differences in opinion, it is sufficient to state that with a few corrections, the *marginal* cost of NO_X control is cost-effective for the original intended operation of 4.420 equivalent hours of operation. For example, EPA Region 4 estimated the cost-effectiveness at $6,120 which would be cost-effective whether it is on a marginal or an average basis. The *average* cost, had it been provided by KEYS and reviewed by the Department and EPA, would easily be cost-effective.

Table 9 is an updated cost-effectiveness analysis submitted by KEYS. It includes estimates of *average* cost-effectiveness for NO_X control by water injection and by a combination of water injection and SCR. It also includes an estimate of the *marginal* cost-effectiveness between the two strategies. The analyses were based on their revised request of 2,500 hours of operation per year instead of continuous operation and the "fuel equivalent" of 4,420 hours per year of operation.

As stated earlier, the Department is in disagreement with several key points regarding the cost effectiveness estimates supplied by the applicant. The analysis presented in Table 9, although revised to reflect the newly requested 2,500 operating hours, remains unchanged in regard to the Department's concerns. Though these estimates are believed to be relatively high, the data is useful in demonstrating some important concepts.

The vast disparity between marginal vs average costs should be noted. Clearly even with operation limited to 2,500 hours, SCR is cost effective from an *average* standpoint. Based on the KEYS estimate however, from a *marginal* standpoint, SCR appears to be less cost effective.

It should also be noted that the cost effectiveness presented in this table was based on a reduction from approximately 87 tons per year to 10 TPY. In actuality, prior to reaching 2,500 operating hours, the unit will be producing 60 TPY or less, thus making the reduction even less cost effective ($22,000/ton). Compound this with the fact that once SCR is in place, the unit need only remain under 40 TPY to avoid PSD applicability. In this case, the cost effectiveness from a *marginal* standpoint of the reduction from 60 to 40 TPY begins to reach extreme proportions ($54,000/ton). These estimates are based on projected fuel usage and equivalent operating hours supplied by KEYS and presented in Table 10.

Other circumstances unique to this project that have been considered by the Department include the following:

- The KEYS project is unique in that it is located on an island, virtually isolated from the mainland, but for a single highway. This isolation adds to the cost and reliability of delivery of goods.
- In the event of a major hurricane strike, Keys residents most likely must rely on locally supplied power. The addition of this unit to the existing facility will ensure the needs of the residents will be met during such an emergency.
- The total project size is very small. It consists of only one 48 MW unit that will operate on a limited basis for at least the first few years following startup. According to projected fuel usage and equivalent operating hours submitted by KEYS, this unit is expected to operate for less than 2,000 equivalent full load hours during the first 4 years of operation.

The Department has concluded that based on marginal and average analysis, SCR is cost effective once 2,500 hours of operation has been reached and likely prior to that. However, taking into consideration the unique circumstances associated with this project, the Department will allow the applicant to defer the installation of SCR until the unit reaches 2,500 hours of annual operation, when it is obviously cost effective from both a marginal and an average standpoint.

Table 9. Average and Marginal Cost-Effectiveness for NO_X Control Options

	WI Alone Average C.E.	WI + Plus SCR Average C.E.	WI + SCR vs WI Marginal C.E.
	Dollars	Dollars	Dollars
Total Direct Cost (DC)	**$477,018**	**$3,606,018**	**$3,129,000**
Indirect Capital Cost			
Contingency	$95,000	$721,000	$626,000
Engineering & Supervision	$48,000	$361,000	$313,000
Construction & Field Exp.	$24,000	$180,000	$156,000
Construction Fee	$48,000	$361,000	$313,000
Startup Assistance	$10,000	$73,000	$63,000
Performance Test	$5,000	$36,000	$31,000
Total Indirect Cap. Cost	**$230,000**	**$1,732,000**	**$1,502,000**
Installed Costs	**707,018**	**5,338,018**	**4,631,000**
-SCR Catalyst Cost		-$317,000	-$317,000
Total Capital Investment (TCI)	**$707,018**	**$5,021,018**	**$4,314,000**
Direct Annual Costs	**Dollars**	**Dollars**	**Dollars**
Catalyst Replacement		$145,182	$145,182
Operating & Maintenance	$13,000	$83,000	$70,000
Water Usage	$184,500	$184,500	
Reagent Feed (Ammonia/Water)		$27,985	$27,985
Power Consumption	$3,703	$24,056	$20,353
Lost Power Generation			
Water Injection Equipment	$-592,500	$-592,500	
Backpressure		$63,320	$63,320
Catalyst Replacement		$48,661	$48,661
Increased Fuel Consumption	$136,649	$136,649	
Annual Distribution Check		$55,000	55,000
Total Direct Annual Costs	**$-254,648**	**$175,852**	**$430,501**
Indirect Annual Costs			
Overhead	$7,800	$49,800	$42,000
Administrative Charges	$14,140	$107,140	$93,000
Property Taxes			
Insurance	$7,070	$53,070	$46,000
Capital Recovery	$77,560	$551,560	$474,000
Total Indirect Annual Costs	**$106,570**	**$761,570**	**$655,000**
Total Annualized Costs	**$-148,078**	**$937,423**	**$1,085,501**
Annual Tons NOx Produced	**87.1**	**87.1**	**87.1**
Annual Tons NOx Not Produced or Removed	**533.1**	**609.8**	**76.8**
Annual Tons NOx Emitted	**87.1**	**10.4**	**10.4**
Cost Effectiveness ($/ton)	**$-278**	**$1,537**	**$14,134**

Table 10. Projected Fuel Usage and Equivalent Operating Hours

Year	Hours of Operation	Gallons Fuel Burned	Equivalent Full Load Hours	NOx Produced in Tons
2006	1,905	3,740,000	1,219	42.5
2007	2,259	4,436,000	1,446	50.4
2008	2,648	5,200,000	1,988	59.1
2009	3,107	6,100,000	2,282	69.3
2010	3,565	7,000,000	2,542	79.5
2011	3,972	7,800,000	2,770	88.6
2012	4,329	8,500,000	2,999	96.5
2013	4,685	9,200,000	3,295	104.5
2014	5,149	10,110,000	3,651	114.8

D. NO_X BACT Emission Limits

The Department will set a NO_X limit of 42 ppmvd @15% O_2 while firing oil and 15 ppmvd @ 15% O_2 while firing natural gas. Compliance with these limits must be demonstrated during an initial test and during annual tests thereafter. Compliance with the 15 ppm limit on gas will be required when natural gas becomes available to the Keys. These limits apply for the restricted operation of 2500 hours per year requested by the applicant.

If in the future there is a need to relax the requested restriction on hours, alternative limits would have to be met. The use of SCR and an emissions limit of 5.0 ppmvd value reflect BACT with operation greater than 2,500 hours. However a 9.0 ppmvd value based on the fuel use limitation requested in the original application would limit NO_x emissions to less than 40 tons per year. These limits for operation greater than 2,500 hours have been incorporated into the permit.

The Department would revise the higher long term limit downward in conjunction with any additional increases in fuel use. A continuous NO_x limit of 5 ppmvd @ 15% O_2 while firing fuel oil must be met at that time.

4.3 <u>Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination</u>

In the original application based on the use of 13,567,000 gallons per year (4,420 equivalent hours) of fuel oil No. 2, the potential of SO_2 and SAM emissions are reported as 47.8 TPY and 14.6 TPY respectively. This exceeds their significant emission rates of 40 TPY and 7 TPY requiring BACT determinations for both pollutants.

However, BACT determinations for SO_2 and SAM are not required based on the revised emission estimates (2,500 operating hours) submitted by KEYS. The revised potential emissions of SO_2 and SAM are 29.5 and 6.8 TPY respectively.

The applicant has indicated that if there is a future need to relax the requested restriction on hours (> 2,500), that they would take practicably enforceable limits of 39.9 TPY SO2 and 6.9 TPY SAM to avoid BACT determinations for these pollutants.

The following are the BACT analyses for SO_2 and SAM based on the use of 13,567,000 gallons per year (4,420 equivalent hours) of fuel oil No. 2 as presented in the original application.

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.

The applicant referred to a table in a Department of Energy analysis of the cost impact of a regulation requiring a complete replacement of the standard specification (0.05% S) highway diesel fuel by 0.0015% sulfur diesel by 2011.

A portion of the table is reproduced below.

Table E1. End-Use Prices and Total Supplies of Highway Diesel, 1999 and 2007-2015, Assuming 6-Percent Return on Investment

Analysis Case	1999	2007	2008	2009	2010	2011	2015	2007-2010 Average	2011-2015 Average
End-Use Prices of Highway Diesel (1999 Cents per Gallon)[a]									
Reference (500 ppm)	114.0	121.6	122.3	123.0	123.6	124.1	124.3	122.6	124.3
Regulation (ULSD)	NA	128.6	129.0	129.5	130.4	131.3	129.4	129.4	129.7
Higher Capital Cost (ULSD)	NA	129.4	129.9	130.5	131.2	132.2	130.1	130.3	130.6
2/3 Revamp (ULSD)	NA	128.9	129.2	129.9	130.7	131.7	129.7	129.7	130.0
10% Downgrade (ULSD)	NA	129.0	129.4	129.9	130.8	133.2	130.0	129.8	130.7
4% Efficiency Loss (ULSD)	NA	128.6	129.0	129.5	130.5	131.4	129.6	129.4	130.0
1.8% Energy Loss (ULSD)	NA	128.9	129.3	129.6	130.5	131.5	129.5	129.6	129.8
Severe (ULSD)	NA	130.4	130.7	131.4	132.2	134.3	131.1	131.2	131.7
No Imports (ULSD)	NA	130.2	130.4	130.9	131.6	132.9	130.5	130.4	131.1
Total Highway Diesel Supplied (Million Barrels per Day)									
Reference									
Total (500 ppm)	2.43	3.09	3.15	3.21	3.27	3.32	3.55	3.18	3.43
Regulation									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	2.43	3.10	3.16	3.22	3.28	3.40	3.63	3.19	3.51
Higher Capital Cost									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	2.43	3.10	3.16	3.22	3.28	3.40	3.63	3.19	3.51
2/3 Revamp									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	2.43	3.10	3.16	3.22	3.28	3.40	3.63	3.19	3.51

According to the applicant:

> *"In the Regulation case, the marginal annual pump price for ULSD is projected to range from 6.5 to 7.2 cents per gallon between 2007 and 2011. The peak differential is projected to occur in 2011, when oil refiners must produce 100 percent ULSD."*

The applicant inferred from the table that difference shown between the Reference (0.05% S) case and the Regulation case (ULSD – 0.0015% S) represents market price differences. In fact, it actually represents the price differential of regulating diesel sulfur compared to what the price would have been in the absence of regulation.

For example, the table indicates a price difference of 7.2 cents per gallon in 2011. This is one of the values mentioned in the quoted excerpt from the application. It would be meaningless to discuss price differences in 2011 between available grades when the table specifically presumes no 0.05% sulfur fuel will be available.

EPA mandated the new grade of diesel because of the contribution of SO_2 to the formation of fine particulate matter in the environment as well as the possibility of poisoning catalysts used to control pollution from diesel engines. It is not unreasonable to require use of the superior grade as BACT in new exclusively diesel-fired sources of air pollution.

In the original application, KEYS estimates that maximum annual SO_2 emissions are 48 TPY based on use of 13,567,000 gallons of fuel oil No. 2 (4,420 equivalent hours). This assumes all sulfur is converted to SO_2. KEYS also assumes SAM emissions of 15 TPY. If the SAM emission estimate is correct, then SO_2 emissions will be equal to approximately 36 TPY which is less than the significant emission rate for SO_2.

Even if the KEYS SO2 emission estimates are correct, projections provided by KEYS indicate fuel oil use sufficient to cause 48 TPY of SO_2. Emissions will not actually reach that level until 2017. The fuel use corresponding to 40 TPY (the significant emission rate for SO_2) is 11,200,000 gallons. This level will not be reached until 2015.

It is doubtful that KEYS will ever emit more than 40 TPY based on:

- Correction of double-counting of sulfur as SO_2 and SAM
- Projected fuel use through 2015;
- Typical delivered sulfur content of low sulfur fuel oil (actually less than 0.05);
- Ultimate availability of ultralow sulfur at little or no premium.

The Department's BACT analyses for SO_2 and SAM control at operation beyond 2,500 hours indicate use of ultralow sulfur diesel fuel. However, KEYS has requested practicably enforceable limits of 39.9 tons of SO_2 and 6.9 tons of SAM per year to avoid BACT determinations and are proposing the use of 0.05 % sulfur fuel oil by weight. The SO_2 limit of 39.9 TPY will provide assurance, even assuming a worst case scenario of an SO_2 oxidation rate of 15% conversion of SO_2 to SO_3, and an assumed 100% conversion of SO_3 to H_2SO_4, that SAM emissions will remain below the significant level of 7.0 TPY.

Note: The Department can allow subtraction of the portion of sulfur that becomes SAM from the SO_2 calculation for the purposes of PSD applicability. This is irrespective of whether or not such a consideration is allowed for the purpose of determining use of SO_2 allowances under the Acid Rain Program.

4.4 Particulate Matter (PM/PM_{10}) BACT Determination

PM/PM_{10} Formation and Control Options

PM and PM_{10} are emitted from combustion turbines due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Low sulfur distillate fuel oil will be the only fuel fired and is efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure.

Applicant's PM/PM_{10} Proposal

KEYS proposed a BACT emission limit of 25 lb/hr for PM and the same value for PM_{10}. The most recent determination (City of Tallahassee) by the Department for an LM6000 PC SPRINT while operating on fuel oil is 15 lb/hr for PM and the same value for PM_{10}. However, the compliance method is a visible emission standard of 10%.

Department's Draft PM/PM_{10} BACT Determinations

The following conditions are established as the draft BACT standards.

- The gas turbines shall fire distillate oil that contains no more than 0.05% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

5. NEW SOURCE PERFORMANCE STANDARDS

5.1 Combustion Turbines

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These requirements result in the following standards based on compressor inlet conditions of 59° F and 60% relative humidity:

- NO_X (oil) ≤ 106 ppmvd @ 15% O_2 (corrected for a heat rate of 10.20 kJ/watt-hr assuming no fuel bound nitrogen; and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

A more recent standard was proposed by EPA on February 18, 2004. The proposed standard, 40 CFR60, Subpart KKKK would require adherence to the following limits:

- NO_X (oil) ≤ 1.2 lb/megawatt-hour. This is approximately equal to 35 ppmvd @15% O_2.
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.05% by weight.

The Department considers the draft BACT standards more stringent than the existing or the proposed NSPS standards. The GE LM6000 PC SPRINT will not meet the proposed NO_X standard without additional control such as proposed by the Department. The Department will request that EPA make a determination regarding KKKK applicability to the present project during the public comment period.

6. AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

In the original application, the proposed project predicted increases in emissions of four pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, NO_X, SO_2, and SAM. In the revised application, the predicted increases in emissions of two pollutants are at levels in excess of PSD significant amounts: PM/PM_{10} and NO_X. The following analyses are based on the revised application. PM_{10} 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.

6.2 Climate

The annual average high temperature for Key West is 83 degrees with their highest reported temperature being 98 degrees in 1997. The annual average low is 73 degrees. According to the National Weather Service in Key West, there is no known record of frost, ice, sleet, or snow in Key West. Prevailing easterly tradewinds and sea breezes suppress the usual summertime heating. Humidity remains relatively high during the entire year.

The wind rose below depicts the winds at Key West from 1987–1990, which are predominately from the east.

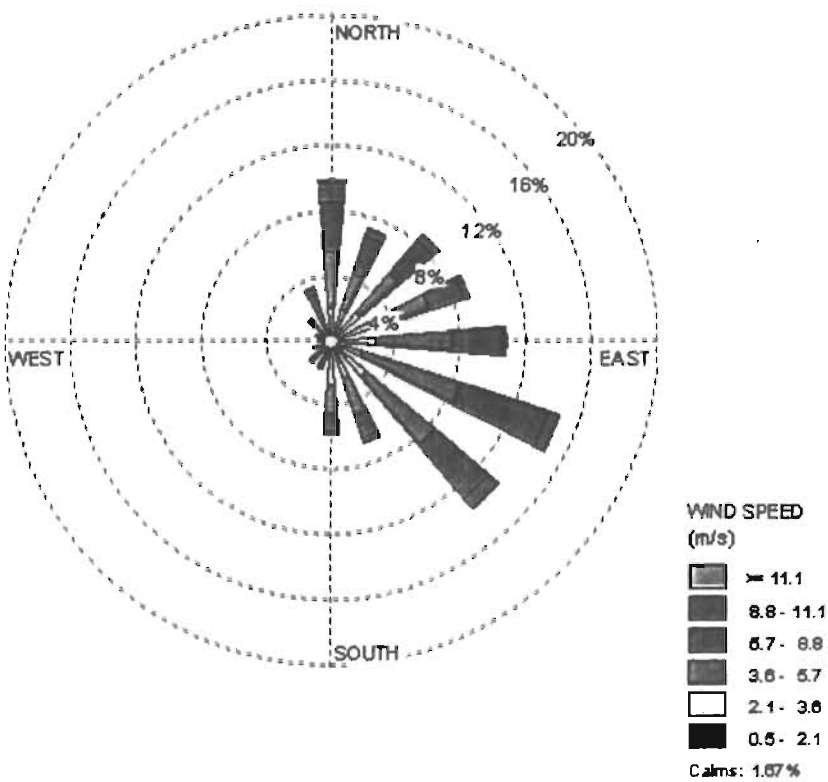


Figure 14 – Key West Wind Rose – 1987 to 1990

6.3 Major Stationary Sources in Monroe County

The current largest stationary sources of air pollution in Monroe County are listed below. The information is from annual operating reports submitted to the Department except as noted.

Table 11. Major Sources of NO_X in Monroe County (2003)

Owner	Site Name	Tons per year
KEYS Energy Services	Stock Island Power Plant (existing)	290**
KEYS Energy Services	***Stock Island Power Plant (proposed)***	***94.9***
City of Key West	Southernmost Waste to Energy Facility	83
KEYS Energy Services.	Cudjoe Key	63*
FL Keys Electric COOP Assoc.	FL Keys Electric COOP Assoc.	45

** Recently shut down*

***Potential to emit from Construction Permit*

Table 12. Major Sources of PM in Monroe County (2003)

Owner	Site Name	Tons per year
KEYS Energy Services	***Stock Island Power Plant (proposed)***	***31.3***
KEYS Energy Services	Stock Island Power Plant (existing)	37*
City of Key West	Southernmost Waste to Energy Facility	8
FL Keys Electric COOP Assoc.	FL Keys Electric COOP Assoc.	6

**Potential to emit from Construction Permit*

Emissions from the proposed project and the existing Stock Island Power Plant are the highest in the county. However, Monroe County does not have as many stationary sources as other Florida Counties and therefore, the conclusion that the emissions from Stock Island are high due to the information in the above tables cannot be made.

6.4 Air Quality and Monitoring in the Monroe County

Monroe County does not have an ambient air quality monitoring network. However, due to the location, climate, size and population of the county, it is assumed that air pollutant concentrations are less than other areas that have monitoring networks, such as Miami-Dade. The entire state of Florida is in attainment for all criteria pollutants.

6.5 Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for PM/PM_{10} and NO_X. 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 SILs for the PSD Class I Everglades National Park (ENP) and the PSD Class II Areas (everywhere except the ENP).

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

The applicant's initial PM/PM_{10}, and NO_X air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except ENP). These values are tabulated in the table below and are compared with existing National Ambient Air Quality Standards.

Table 13. Maximum Projected Air Quality Impacts from Stock Island Unit 4 for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.1	1	50	NO
	24-Hour	4.9	5	150	NO
NO_2	Annual	0.2	1	100	NO

Maximum predicted impacts from the project are much less than the respective AAQS 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 Everglades National Park (ENP) located about 90 km to the northeast 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}, and NO_X air quality impact analyses for this project indicated that maximum predicted impacts are less than the applicable SILs for the Class I area. Therefore no further detailed modeling efforts are required.

Table 14. Maximum Air Quality Impacts from the Stock Island Unit 4 Project for comparison to the PSD Class I SILs at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.0004	0.2	NO
	24-hour	0.02	0.3	NO
NO_2	Annual	0.0005	0.1	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 15. 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)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4.9	10	NO
NO_2	Annual	0.2	14	NO

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 Air Quality Analysis

PSD Class II Area: The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition.

The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. 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.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from Key West and West Palm Beach respectively. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

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 California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP. Meteorological MM4 and MM5 data used in this model was from 1990, 1992 and 1996.

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.

6.6 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Very low emissions are expected from gas turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, and NO_X as a result of the proposed project, including background concentrations, will be considerably less than the respective AAQS.

Since the project impacts are less than significant or considerably less than the AAQS, it is reasonable to assume the impacts on soils, vegetation, or wildlife (including the Endangered Key Deer) will be minimal or insignificant.

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 substantially lower than the significant impact levels (0.01 kg/ha/yr) determined by the National Park Service.

In addition, the National Park Service reviewed the proposal for CT Unit 4 at Stock Island and concluded that they "believe that there will not be any significant impacts on resources at the Everglades National Park."

Impact on Visibility:

The applicant submitted a visibility analysis for the Everglades National Park. The analysis included modeling from the CALPUFF model. The CALPUFF model predicted modeled impacts well below the 5% visibility impairment based on criteria from the NPS.

Growth-Related Impacts Due to the Proposed Project:

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth near the project.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, the population of Key West and Monroe County has grown by an average of 2% per decade since 1980. The population of Monroe County is currently about 80,000. In 1980, it was 63,000. In 1990, Stock Island had a population of about 3,600. The county depends on tourism economically. In 2000, 30% of the population worked in the tourism industry. With tourism being the main economic support for the Keys, the area is not a major industrial center. The main non-tourist related "industry" in the Keys is the military presence in the area.

Since 1977, there have been several projects at Stock Island including construction of two 8.8 MW diesel engines in 1990-91. One 23.5 MW combustion turbine was moved from Key West to Stock Island in 1995-96. Two 20 MW combustion turbines were installed in 1998. The Ralph Garcia Steam Unit was permanently retired in the 1980's. For reference, that unit still holds 2571 SO_2 allowances under the Federal Acid Rain program.

Southernmost Resource Recovery Facility surrendered its Title V Operation Permit in 2004 and permanently shut down.

Mobile source fuel quality has improved since the 1970's. The related reduction in transportation-related NO_X, SO_2 and VOC emissions probably offset increases due to traffic growth. The transportation-related decreases and the retirement of the Ralph Garcia Steam Plant and Southernmost Resource Recovery Facility provide a basis for concluding that there has not been a deterioration of air quality in the lower Keys since 1977. The proposed project is not likely to change that conclusion.

7.0 Preliminary Determination

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit.

Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Alvaro Linero, P.E., is the project engineer responsible for preparing the draft BACT determination and the permit as well as evaluating projecting the impacts on fuel supply. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

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[21] Environmental Assessment. Long Island Power Authority, Jamaica Bay Energy Center. FPL Energy, LLC. November 2002.

[22] Telecom. Linero, A., Florida DEP and Seal, H., Envirokinetics. SCR Applications at Bayswater and Jamaica Bay. February 24, 2005.

[23] Memorandum. Davis, R. E., BWP to Alvord, M. J., City Manager. LM6000 SCR Upgrade and NO_X Catalyst Replacement. Council Agenda Item No. 9. City of Burbank. February 15, 2005.

From: DEP AIR RESOURCE MGMT
P. Adams
111 S MAGNOLIA DR
TALLAHASSEE, FL 32301
UNITED STATES

EXP

Parcels: 1/1

ORIGIN: TLH

Sender's ref
37550201000 A7 AP255

To: National Park Service
Mr. John Bunyak
12795 W. Alameda Parkway
Air Division
Lakewood, CO 80228
UNITED STATES

POST CODE:
80228

Tel: 303-966-2818

Description:

Weight: 4 lbs for 1 pcs
Date: 2005-04-20

DHL standard terms and conditions apply.

EGEH 8E

(2L)US80228

WAYBILL: 25929628152 (Non-Negotiable)

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SENDER'S RECEIPT
Waybill #: 25929628152

To(Company):
National Park Service ,
Air Division
12795 W. Alameda Parkway

Lakewood, CO 80228
UNITED STATES

Attention To: Mr. John Bunyak
Phone#: 303-966-2818

Sent By: P. Adams
Phone#: 850-921-9505

Rate Estimate: 15.96
Protection: Not Required
Description:

Weight (lbs.): 4
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Next Day 12:00 (Next business day by 12 PM)

Special Svc:

Date Printed: 4/20/2005
Bill Shipment To: Sender
Bill To Acct: 778941286

DHL Signature (optional) ____________________ Route ______ Date ______ Time ______

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TRACKING RESULTS: DETAIL

Tracking Number: **23541379455**

Shipment Summary:

Current Status:	Shipment delivered.
Delivered on:	10/29/04 11:28 am
Delivered to:	Receptionist
Signed for by:	C CARDONA

Ge

Shipment History:

DATE	TIME	ACTIVITY AND COMMENTS	LOCATION
10/29/04	11:28 am	Shipment delivered.	Fort Myers, FL
	8:21 am	Arrived at DHL facility.	Fort Myers, FL
	1:30 am	Departing origin.	Orlando, FL
10/28/04	4:29 pm	Picked Up by DHL.	Shipper's Door

Shipper:

DEP AIR RESOURCE MGMT
Tallahassee, FL 32301
United States

Receiver:

DEP SOUTH DISTRICT OFFICE
Fort Myers, FL 33901
United States

Shipment Detail:

Service:	Next Day AM	Ship Type:	Package
Special:		Description:	BOOK
Weight:	3	Shipper's Reference:	37550201000 A7 AP255
Pieces:	1		

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- Tracking detail provided by DHL: 11/10/2004, 11:57:28 am pt.
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- You are authorized to use DHL tracking systems solely to track shipments tendered by or for you to [use of DHL tracking systems and information is strictly prohibited.

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SENDER'S RECEIPT
Waybill #: 23541379455

To(Company):
DEP South District Office
Suite 364
2295 Victoria Avenue

Fort Myers, FL 33901
UNITED STATES

Attention To: Mr. Ron Blackburn
Phone#: 239/332-6975

Sent By: P. Adams
Phone#: 850-921-9595

Rate Estimate: $6.38
Protection: Not Required
Description: book

Weight (lbs.): 5
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Next Day 12:00 (Next business day by 12 PM)

Special Svc:
COD Amount: $ 0.00
Payment Options:
Date Printed: 10/28/2004
Bill Shipment To: Sender
Bill To Acct: 778941286

DHL Signature (optional) __________________________ Route ______ Date ______ Time ______

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TRACKING RESULTS: DETAIL

Tracking Number: 23555720053

Shipment Summary:

Current Status:	Shipment delivered.
Delivered on:	11/1/04 11:36 am
Delivered to:	Mail Room
Signed for by:	D CHANDLER

Ge

Shipment History:

DATE	TIME	ACTIVITY AND COMMENTS	LOCATION
11/1/04	11:36 am	Shipment delivered.	Downtown Atlanta, GA
10/30/04	7:50 am	Arrived at DHL facility.	Downtown Atlanta, GA
	12:49 am	Departing origin.	Atlanta, GA
10/29/04	3:48 pm	Picked Up by DHL.	Shipper's Door

Shipper:

DEP AIR RESOURCE MGMT
Tallahassee, FL 32301
United States

Receiver:

U.S. EPA REGION 4
Atlanta, GA 30303
United States

Shipment Detail:

Service:	Next Day AM	Ship Type:	Package
Special:		Description:	BOOK
Weight:	2	Shipper's Reference:	37550201000 A7 AP255
Pieces:	1		

New Search | Get Signature P.O.D.

- Tracking detail provided by DHL: 11/10/2004, 12:04:25 pm pt.
- For assistance, please contact us.
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SENDER'S RECEIPT
Waybill #: 23555720053

To(Company):
U.S. EPA Region 4
Air Permits Section
61 Forsyth Street

Atlanta, GA 30303
UNITED STATES

Attention To: Mr. Gregg M. Worley
Phone#: 404-562-9141

Sent By: P. Adams
Phone#: 850-921-9595

Rate Estimate: $6.38
Protection: Not Required
Description: book

Weight (lbs.): 5
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Next Day 12:00 (Next business day by 12 PM)

Special Svc:
COD Amount: $ 0.00
Payment Options:
Date Printed: 10/29/2004
Bill Shipment To: Sender
Bill To Acct: 778941286

DHL Signature (optional) ______________________ Route ______ Date ______ Time ______

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TRACKING RESULTS: DETAIL

Tracking Number: **23556089454**

Shipment Summary:

Current Status:	Shipment delivered.
Delivered on:	11/1/04 10:06 am
Delivered to:	Receptionist
Signed for by:	A HENSON

Ge

Shipment History:

DATE	TIME	ACTIVITY AND COMMENTS	LOCATION
11/1/04	10:06 am	Shipment delivered.	West Denver, CO
10/30/04	7:50 am	Arrived at DHL facility.	West Denver, CO
10/29/04	6:27 pm	Departing origin.	Tallahassee, FL
	3:48 pm	Picked Up by DHL.	Shipper's Door

Shipper:

DEP AIR RESOURCE MGMT
Tallahassee, FL 32301
United States

Receiver:

NATIONAL PARK SERVICE
Lakewood, CO 80228
United States

Shipment Detail:

Service:	Next Day AM	Ship Type:	Package
Special:		Description:	BOOK
Weight:	5	Shipper's Reference:	37550201000 A7 AP255
Pieces:	1		

New Search | Get Signature P.O.D.

- Tracking detail provided by DHL: 11/10/2004, 12:02:57 pm pt.
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SENDER'S RECEIPT
Waybill #: 23556089454

To(Company):
National Park Service
Air Division
12795 W. Alameda Parkway

Lakewood, CO 80228
UNITED STATES

Attention To: Mr. John Bunyak
Phone#: 303-966-2818

Sent By: P. Adams
Phone#: 850-921-9595

Rate Estimate: $17.77
Protection: Not Required
Description: book

Weight (lbs.): 5
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Next Day 12:00 (Next business day by 12 PM)

Special Svc:
COD Amount: $ 0.00
Payment Options:
Date Printed: 10/29/2004
Bill Shipment To: Sender
Bill To Acct: 778941286

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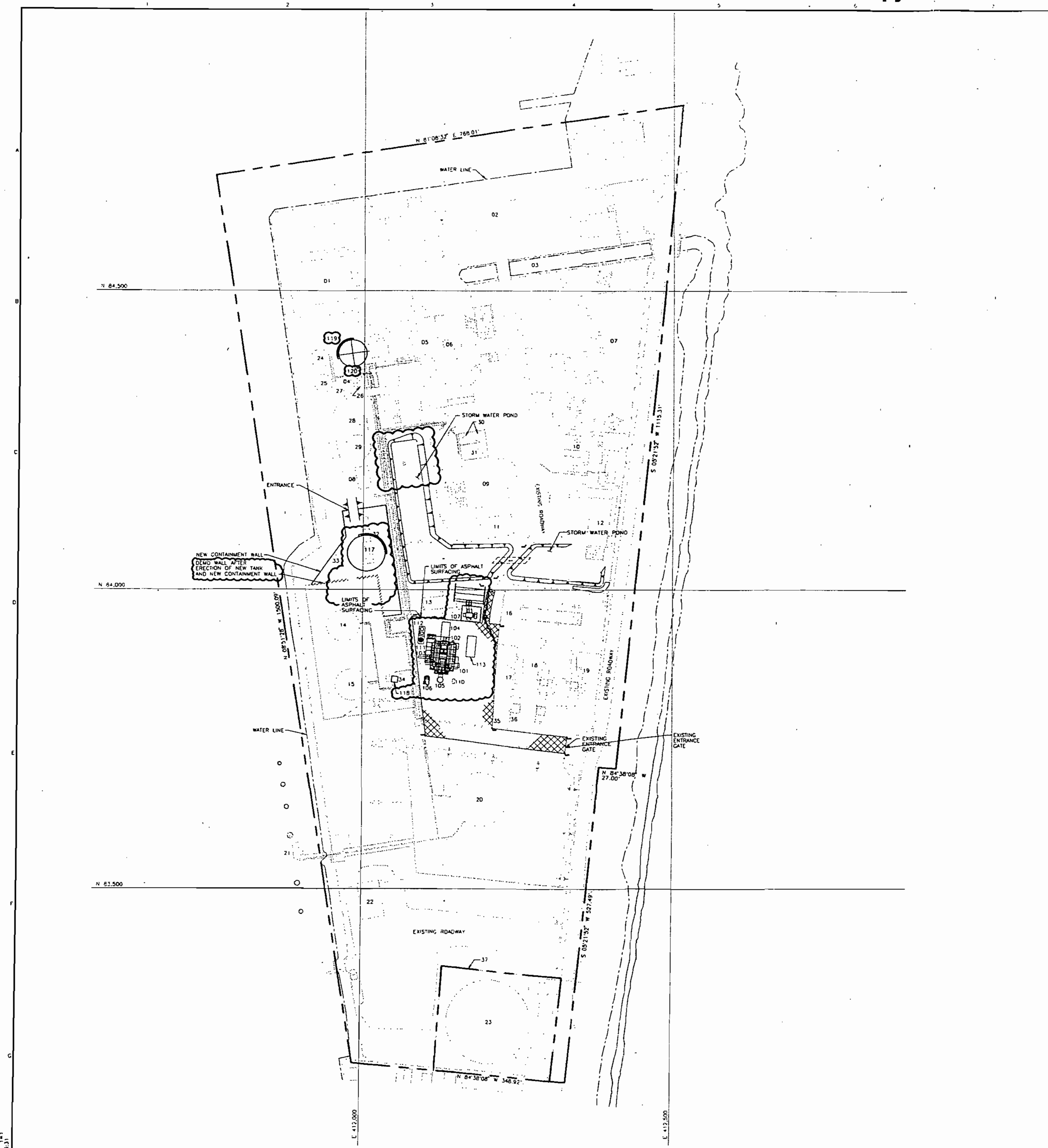

EXISTING FACILITIES LEGEND

ID	FACILITY	FOUNDATION	TIEDOWN LOCATION NORTH	TIEDOWN LOCATION EAST	REMARKS
01	WAREHOUSE	-	-	-	
02	WAREHOUSE	-	-	-	
03	CIRCULATING WATER DISCHARGE FLUME	-	-	-	
04	RETIRED STEAM UNIT STACK	-	-	-	
05	RETIRED STEAM UNIT	-	-	-	
06	SYNCHRONOUS CONDENSER	-	-	-	
07	STOCK ISLAND SUBSTATION	-	-	-	
08	FIRE PUMP HOUSE	-	-	-	
09	MEDIUM SPEED DIESEL GENERATOR BUILDING	-	-	-	
10	HIGH SPEED DIESELS	-	-	-	
11	VEHICLE MAINTENANCE LIFT	-	-	-	
12	MAINTENANCE GARAGE	-	-	-	
13	STORAGE AREA	-	-	-	TO BE RELOCATED
14	DIESEL FUEL TANK (500,000 GALLONS, 32' HIGH)	-	-	-	
15	DIESEL FUEL TANK (500,000 GALLONS, 32' HIGH)	-	-	-	
16	SWITCHYARD	-	-	-	
17	COMBUSTION TURBINE GENERATOR #1	-	-	-	
18	COMBUSTION TURBINE GENERATOR #2	-	-	-	
19	COMBUSTION TURBINE GENERATOR #3	-	-	-	
20	DIESEL FUEL TANK (1.9 MILLION GALLONS, 40' HIGH)	-	-	-	
21	FUEL LOADING DOCK	-	-	-	
22	TWO-STORY OFFICE BUILDING	-	-	-	
23	FKAA WATER TANK	-	-	-	
24	DEMINERALIZED WATER TANK (169,000 GALLONS, 32' HIGH)	-	-	-	
25	DEMINERALIZED WATER TANK (169,000 GALLONS, 32' HIGH)	-	-	-	
26	CEMS BUILDING FOR RETIRED STEAM UNIT	-	-	-	
27	CINGULAR CEL TOWER CONTROL BUILDING	-	-	-	
28	ABANDONED TANK STORAGE SHED	-	-	-	
29	SERVICE/FIRE WATER TANK (300,000 GALLONS, 40' HIGH)	-	-	-	
30	FUEL OIL DAY TANKS	-	-	-	
31	LUBE OIL STORAGE TANK	-	-	-	
32	STORAGE SHEDS	-	-	-	TO BE RELOCATED
33	FIRE HYDRANT	-	-	-	TO BE RELOCATED
34	FUEL OIL FORWARDING BUILDING	-	-	-	
35	STORAGE BUILDING	-	-	-	
36	WATER INJECTION SKID	-	-	-	
37	FLORIDA KEYS AQUADUCT AUTHORITY PROPERTY LINE	-	-	-	

NEW FACILITIES LEGEND

ID	FACILITY	FOUNDATION	TIEDOWN LOCATION NORTH	TIEDOWN LOCATION EAST	REMARKS
101	COMBUSTION TURBINE (CT)	-	-	-	
102	COMBUSTION TURBINE GENERATOR	-	-	-	
103	COMBUSTION TURBINE AUXILIARY SKID	-	-	-	
104	GENERATOR ROTOR REMOVAL AREA	-	-	-	
105	STACK	-	-	-	
106	CONTINUOUS EMISSIONS MONITORS (CEMS)	-	-	-	
107	GENERATOR STEP-UP TRANSFORMER	-	-	-	
108	GENERATOR CIRCUIT BREAKER (LOCATED IN AUX ELEC MOD -SEE ITEM 113)	-	-	-	
109	UNIT AUXILIARY TRANSFORMER (LOCATED IN AUX ELEC MOD -SEE ITEM 113)	-	-	-	
110	WATER WASH SUMP	-	-	-	
111	FIN FAN COOLER	-	-	-	
112	AIR COMPRESSOR SKID	-	-	-	
113	AUXILIARY ELECTRICAL EQUIPMENT MODULE	-	-	-	
114	480V DISTRIBUTION SWITCHGEAR (LOCATED IN AUX ELECT MOD -SEE ITEM 113)	-	-	-	
115	NOT USED	-	-	-	
116	NOT USED	-	-	-	
117	DIESEL FUEL OIL TANK (1 MILLION GALLONS, 48' HIGH)	-	-	-	
118	FUEL OIL FORWARDING SKID	-	-	-	
119	DEMINERALIZED WATER STORAGE TANK (350,000 GALLONS, 32' HIGH)	-	-	-	
120	DEMINERALIZED WATER PUMP SKID	-	-	-	

GENERAL LEGEND

PROPERTY BOUNDARY
EXISTING FENCE
EXISTING OVERHEAD TRANSMISSION LINES
WATER LINE
NEW FENCE
EXISTING CONTAINMENT WALL TO BE DEMOLISHED
ASPHALT SURFACING
GRAVEL SURFACING

NOTES

1. THIS SPECIAL PURPOSE SURVEY WAS PERFORMED TO ESTABLISH SITE CONTROL MONUMENTS WITH AERIAL TARGETING FOR USE IN PHOTOGRAMMETRIC MAPPING OF THE SITE. THE BOUNDARY LINES WITH BEARINGS AND LENGTHS DEPICTED HEREON WERE PLOTTED FROM INFORMATION PROVIDED BY THE CLIENT. THE BOUNDARY LOCATION IS APPROXIMATE, AS GRAPHICALLY SCALED FROM DRAWINGS PROVIDED BY THE CLIENT, AND SHOULD NOT BE RELIED UPON FOR BOUNDARY SURVEY DETERMINATION.
2. VERTICAL CONTROL IS BASED ON THE NORTH AMERICAN VERTICAL DATUM OF 1988 (NAVD 88). ELEVATIONS ARE EXPRESSED IN FEET, AND DECIMALS THEREOF. TO CONVERT ELEVATIONS FOR THE STOCK ISLAND AREA FROM NAVD 88 TO THE NGVD 29 DATUM, USE THE FOLLOWING CONVERSION:
NAVD 88 + 1.34' = NGVD 29.
3. HORIZONTAL CONTROL DATA IS BASED ON FLORIDA STATE PLANE COORDINATE SYSTEM (EAST ZONE), NORTH AMERICAN DATUM OF 1983 (NAD 83) WITH THE 1999 ADJUSTMENT. COORDINATE VALUES ARE EXPRESSED AS "GRID COORDINATES" AND ARE IN FEET, AND DECIMALS THEREOF. FOR CONVERSION FROM GRID TO GROUND VALUES USE A SITE SCALE FACTOR OF 1.00000943.

PRELIMINARY
NOT TO BE USED
FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	CHK	APP
1	03/28/05	GENERAL REVISIONS	MRR	DAJ	MJS
0	10/01/04	ISSUED FOR BIDS	MRR	DAJ	MJS

SCALE: 1"=60'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED
DATE REG NO

BLACK & VEATCH CORPORATION
ENGINEER DAJ DRAWN MRR
CHECKED DATE

STOCK ISLAND
COMBUSTION TURBINE UNIT 4
SITE ARRANGEMENT
GE LM6000 UNIT

PROJECT: 136839 DRAWING NUMBER: DS-S1001 REV: 1
CODE
AREA

4/8/2005
FMPA
Stock Island-Key West
Black & Veatch Project 136839.004
LM6000 Emissions Estimates, Revision 0, 35% & 20% Load Cases

Case Number	17	13	18	14	19	15	20	16
CTG Model	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	35%	20%	35%	20%	35%	20%	35%	20%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	59	59	78	78	95	95
Ambient Conditions								
Ambient Temperature, F	41.0	41.0	59.0	59.0	78.0	78.0	95.0	95.0
Ambient Relative Humidity, %	100.0	100.0	60.0	60.0	81.8	81.8	60.2	60.2
Atmospheric Pressure, psia	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696
Combustion Turbine Performance								
CTG Performance Reference	GE	GE	GE	GE	GE	GE	GE	GE
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	41.0	41.0	59.0	59.0	78.0	78.0	95.0	95.0
CTG Compr. Inlet Relative Humidity, %	100.0	100.0	60.2	60.2	81.8	81.8	60.3	60.3
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
CTG Load Level (percent of Base Load)	35%	20%	35%	20%	35%	20%	35%	20%
Gross CTG Output, kW	17,446	9,969	16,789	9,592	15,647	8,940	14,244	8,139
Gross CTG Heat Rate, Btu/kWh (LHV)	11,369	14,604	11,573	14,901	11,868	15,406	12,367	16,283
Gross CTG Heat Rate, Btu/kWh (HHV)	12,109	15,553	12,327	15,870	12,642	16,407	13,167	17,341
CTG Heat Input, MBtu/h (LHV)	198.4	145.6	194.3	142.9	185.7	137.7	176.2	132.5
CTG Heat Input, MBtu/h (HHV)	211.3	155.1	207.0	152.2	197.8	146.7	187.6	141.1
CTG Water/Steam Injection Flow, lb/h	8,314	5,426	8,312	5,428	7,182	4,688	6,504	4,312
Injection Fluid/Fuel Ratio	0.8	0.7	0.8	0.7	0.7	0.6	0.7	0.6
CTG Exhaust Flow, lb/h	690,117	600,637	661,828	576,891	630,615	551,561	599,071	526,962
CTG Exhaust Temperature, F	718	672	750	704	776	731	800	759
Combustion Turbine Fuel								
Total CTG Fuel Flow, lb/h	10,780	7,910	10,565	7,770	10,095	7,490	9,570	7,200
CTG Fuel Temperature, F	80	80	80	80	80	80	80	80
CTG Fuel LHV, Btu/lb	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400
CTG Fuel HHV, Btu/lb	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596
HHV/LHV Ratio	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650
CTG Fuel Composition (Ultimate Analysis by Weight)								
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
H2	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%
N2	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

4/8/2005
FMPA
Stock Island-Key West
Black & Veatch Project 136839.004
LM6000 Emissions Estimates, Revision 0, 35% & 20% Load Cases

Case Number	17	13	18	14	19	15	20	16
CTG Model	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	35%	20%	35%	20%	35%	20%	35%	20%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	59	59	78	78	95	95
Stack Emissions								
Stack Exhaust Analysis - Volume Basis - Wet								
Ar	0.94%	0.94%	0.94%	0.94%	0.93%	0.93%	0.92%	0.92%
CO2	3.11%	2.67%	3.18%	2.73%	3.17%	2.74%	3.16%	2.75%
H2O	5.93%	5.06%	6.22%	5.33%	7.62%	6.78%	8.21%	7.43%
N2	74.67%	75.17%	74.47%	74.98%	73.38%	73.85%	72.91%	73.35%
O2	15.37%	16.16%	15.21%	16.02%	14.92%	15.70%	14.81%	15.55%
SO2 (after SO2 oxidation)	0.000579%	0.000499%	0.000595%	0.000510%	0.000590%	0.000510%	0.000590%	0.000510%
SO3 (after SO2 oxidation)	0.000105%	0.000090%	0.000105%	0.000090%	0.000105%	0.000090%	0.000105%	0.000090%
Total	100.00%	100.0%	100.00%	100.0%	100.00%	100.0%	100.00%	100.0%
Stack Exit Temperature, F	718	672	750	704	776	731	800	759
Stack Diameter, ft (estimated)	10	10	10	10	10	10	10	10
Stack Flow, lb/h	690,113	600,634	661,824	576,888	630,611	551,558	599,067	526,959
Stack Flow, scfm	152,381	132,340	146,244	127,204	140,128	122,355	133,417	117,161
Stack Flow, acfm	346,848	288,306	342,252	284,984	334,638	280,377	324,565	274,723
Stack Exit Velocity, ft/s	73.5	61.0	72.5	60.0	71.0	59.0	68.5	58.0
Stack NOx Emissions								
NOx, ppmvd (dry, 15% O2)	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
NOx, ppmvd (dry)	32.8	27.9	33.5	28.5	34.0	29.1	34.1	29.4
NOx, ppmvw (wet)	30.7	26.4	31.4	27.0	31.4	27.1	31.3	27.2
NOx, lb/h as NO2	34.7	25.5	34.0	25.0	32.5	24.1	30.8	23.2
NOx, lb/MBtu (LHV) as NO2	0.1750	0.1749	0.1751	0.1750	0.1750	0.1751	0.1749	0.1749
NOx, lb/MBtu (HHV) as NO2	0.1643	0.1643	0.1644	0.1643	0.1644	0.1644	0.1643	0.1642
Stack CO Emissions								
CO, ppmvd (dry, 15% O2)	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
CO, ppmvd (dry)	11.7	9.9	12.0	10.2	12.2	10.4	12.2	10.5
CO, ppmvw (wet)	11.0	9.4	11.3	9.7	11.2	9.7	11.2	9.7
CO, lb/h	7.6	5.5	7.4	5.4	7.1	5.2	6.7	5.0
CO, lb/MBtu (LHV)	0.0381	0.0380	0.0381	0.0381	0.0381	0.0381	0.0380	0.0380
CO, lb/MBtu (HHV)	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357
Stack SO2 Emissions, after SO2 Oxidation								
SO2, ppmvd (dry, 15% O2)	7.96	7.96	7.96	7.96	7.96	7.96	7.96	7.96
SO2, ppmvd (dry)	6.20	5.28	6.35	5.41	6.43	5.50	6.46	5.57
SO2, ppmvw (wet)	5.82	5.00	5.95	5.12	5.94	5.13	5.92	5.15
SO2, lb/h	9.16	6.72	8.98	6.60	8.58	6.37	8.13	6.12
SO2, lb/MBtu (LHV)	0.0462	0.0462	0.0462	0.0462	0.0462	0.0462	0.0462	0.0462
SO2, lb/MBtu (HHV)	0.0434	0.0433	0.0434	0.0434	0.0434	0.0434	0.0434	0.0434

4/8/2005
FMPA
Stock Island-Key West
Black & Veatch Project 136839.004
LM6000 Emissions Estimates, Revision 0, 35% & 20% Load Cases

Case Number	17	13	18	14	19	15	20	16
CTG Model	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT	LM6000 PC-SPRINT
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	35%	20%	35%	20%	35%	20%	35%	20%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	59	59	78	78	95	95
Stack Emissions - continued								
Stack UHC Emissions								
UHC, ppmvd (dry, 15% O2)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
UHC, ppmvd	7.8	6.6	8.0	6.8	8.1	6.9	8.1	7.0
UHC, ppmvw	7.3	6.3	7.5	6.4	7.5	6.5	7.5	6.5
UHC, lb/h as CH4	2.9	2.1	2.9	2.1	2.7	2.0	2.6	1.9
UHC, lb/MBtu (LHV)	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145
UHC, lb/MBtu (HHV)	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136
Stack VOC Emissions								
VOC, ppmvd (dry, 15% O2)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
VOC, ppmvd (dry)	6.3	5.3	6.4	5.4	6.5	5.5	6.5	5.6
VOC, ppmvw (wet)	5.9	5.0	6.0	5.1	6.0	5.2	6.0	5.2
VOC, lb/h as CH4	2.3	1.7	2.3	1.7	2.2	1.6	2.1	1.5
VOC, lb/MBtu (LHV)	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116
VOC, lb/MBtu (HHV)	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109
PM10 without the Effects of SO2 oxidation								
PM10 Emissions - Front Half Catch Only								
PM10, lb/h	10.6	7.8	10.6	7.8	10.6	7.8	10.6	7.8
PM10, lb/MBtu (LHV)	0.0533	0.0535	0.0544	0.0545	0.0569	0.0565	0.0600	0.0587
PM10, lb/MBtu (HHV)	0.0500	0.0502	0.0510	0.0511	0.0534	0.0531	0.0563	0.0552
PM10 Emissions - Front and Back Half Catch								
PM10, lb/h	19.0	14.0	19.0	14.0	19.0	14.0	19.0	14.0
PM10, lb/MBtu (LHV)	0.0958	0.0962	0.0978	0.0980	0.1023	0.1017	0.1079	0.1057
PM10, lb/MBtu (HHV)	0.0899	0.0903	0.0918	0.0920	0.0961	0.0954	0.1013	0.0992
Total Effects of SO2 Oxidation								
Total SO2 to SO3 conversion rate, %vol	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Total Amount of SO2 converted to SO3, lb/h	1.62	1.19	1.58	1.17	1.51	1.12	1.44	1.08
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	2.48	1.82	2.43	1.78	2.32	1.72	2.20	1.65

Notes:
1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. Standard conditions are defined as 60 F, 14.696 psia, Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas.
5. The CTG performance is from a General Electric estimation program.

4/21/2004
FMPA
Stock Island-Key West
Black & Veatch Project 136833.004
LM6000 Emissions Estimates, Revision 0

Case Number	1	2	3	4	5	6	7	8	9	10	11	12
CTG Model	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	41	59	59	59	78	78	78	95	95	95
Stack Emissions - continued												
Stack UHC Emissions												
UHC, ppmvd (dry, 15% O2)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
UHC, ppmvd	11.2	9.6	9.0	11.3	9.8	9.2	11.3	10.0	9.3	11.3	10.1	9.2
UHC, ppmvw	10.1	8.9	8.3	10.1	9.0	8.5	10.0	9.1	8.5	10.0	9.1	8.4
UHC, lb/h as CH4	6.3	4.9	3.6	6.1	4.8	3.6	5.8	4.5	3.4	5.4	4.2	3.2
UHC, lb/MBtu (LHV)	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145
UHC, lb/MBtu (HHV)	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136
Stack VOC Emissions												
VOC, ppmvd (dry, 15% O2)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
VOC, ppmvd (dry)	8.9	7.7	7.2	9.0	7.8	7.3	9.1	8.0	7.4	9.1	8.1	7.4
VOC, ppmvw (wet)	8.1	7.1	6.7	8.1	7.2	6.8	8.0	7.3	6.8	8.0	7.3	6.7
VOC, lb/h as CH4	5.0	3.9	2.9	4.9	3.8	2.9	4.6	3.6	2.7	4.3	3.4	2.6
VOC, lb/MBtu (LHV)	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116
VOC, lb/MBtu (HHV)	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109
PM10 without the Effects of SO2 oxidation												
PM10 Emissions - Front Half Catch Only												
PM10, lb/h	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
PM10, lb/MBtu (LHV)	0.0320	0.0410	0.0552	0.0329	0.0419	0.0564	0.0348	0.0445	0.0593	0.0375	0.0478	0.0631
PM10, lb/MBtu (HHV)	0.0300	0.0385	0.0518	0.0309	0.0394	0.0530	0.0327	0.0417	0.0557	0.0352	0.0449	0.0592
PM10 Emissions - Front and Back Half Catch												
PM10, lb/h	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
PM10, lb/MBtu (LHV)	0.0576	0.0740	0.0998	0.0593	0.0756	0.1017	0.0627	0.0802	0.1070	0.0677	0.0862	0.1138
PM10, lb/MBtu (HHV)	0.0541	0.0695	0.0935	0.0557	0.0710	0.0955	0.0589	0.0753	0.1004	0.0635	0.0809	0.1058
Total Effects of SO2 Oxidation												
Total SO2 to SO3 conversion rate, %vol	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Total Amount of SO2 converted to SO3, lb/h	4.71	3.67	2.73	4.58	3.59	2.67	4.33	3.38	2.54	4.01	3.15	2.39
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	7.21	5.62	4.18	7.01	5.49	4.09	6.62	5.18	3.89	6.14	4.82	3.65

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. Standard conditions are defined as 60 F, 14.696 psia, Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas.
5. The CTG performance is from a General Electric estimation program.

4/21/2004
FMPA
Stock Island-Key West
Black & Veatch Project 136833.004
LM6000 Emissions Estimates, Revision 0

Case Number	1	2	3	4	5	6	7	8	9	10	11	12
CTG Model	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	41	59	59	59	78	78	78	95	95	95
Stack Emissions												
Stack Exhaust Analysis - Volume Basis - Wet												
Ar	0.91%	0.92%	0.93%	0.91%	0.92%	0.93%	0.89%	0.91%	0.92%	0.89%	0.90%	0.91%
CO_2	4.31%	3.79%	3.54%	4.31%	3.83%	3.62%	4.27%	3.87%	3.60%	4.24%	3.88%	3.57%
H_2O	9.30%	7.59%	6.79%	9.87%	7.90%	7.11%	11.33%	9.26%	8.45%	11.88%	9.85%	8.99%
N_2	72.52%	73.64%	74.17%	72.08%	73.42%	73.95%	70.92%	72.37%	72.90%	70.47%	71.92%	72.46%
O_2	12.96%	14.06%	14.57%	12.84%	13.92%	14.40%	12.59%	13.59%	14.14%	12.52%	13.44%	14.07%
SO_2 (after SO_2 oxidation)	0.000760%	0.000670%	0.000620%	0.000760%	0.000680%	0.000640%	0.000750%	0.000680%	0.000630%	0.000750%	0.000680%	0.000630%
SO_3 (after SO_2 oxidation)	0.000190%	0.000170%	0.000160%	0.000190%	0.000170%	0.000160%	0.000190%	0.000170%	0.000160%	0.000190%	0.000170%	0.000160%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	814	781	763	822	789	796	837	824	820	856	853	840
Stack Diameter, ft (estimated)	10	10	10	10	10	10	10	10	10	10	10	10
Stack Flow, lb/h	1,099,310	979,077	779,592	1,065,780	944,785	746,759	1,011,305	879,155	709,664	942,618	812,986	671,175
Stack Flow, scfm	244,781	217,030	172,421	237,848	209,586	165,284	227,040	196,053	157,901	212,091	181,704	149,673
Stack Flow, acfm	600,044	509,450	405,390	586,716	503,731	399,519	566,335	484,125	388,898	536,825	458,798	374,406
Stack Exit Velocity, ft/s	127.0	108.0	86.0	125.0	107.0	85.0	120.0	103.0	83.0	114.0	97.0	79.0
Stack NOx Emissions												
NOx, ppmvd (dry, 15% O_2)	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
NOx, ppmvd (dry)	47.0	40.5	37.6	47.3	41.2	38.5	47.6	42.1	38.9	47.6	42.6	38.8
NOx, ppmvw (wet)	42.6	37.4	35.0	42.6	37.9	35.8	42.2	38.2	35.6	41.9	38.4	35.3
NOx, lb/h as NO_2	75.9	59.1	43.9	73.7	57.8	43.0	69.7	54.5	40.9	64.7	50.8	38.4
NOx, lb/MBtu (LHV) as NO_2	0.1749	0.1750	0.1750	0.1750	0.1750	0.1751	0.1750	0.1749	0.1749	0.1750	0.1750	0.1749
NOx, lb/MBtu (HHV) as NO_2	0.1643	0.1643	0.1643	0.1643	0.1643	0.1644	0.1643	0.1643	0.1643	0.1643	0.1643	0.1643
Stack CO Emissions												
CO, ppmvd (dry, 15% O_2)	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
CO, ppmvd (dry)	16.8	14.5	13.4	16.9	14.7	13.8	17.0	15.1	13.9	17.0	15.2	13.9
CO, ppmvw (wet)	15.2	13.4	12.5	15.2	13.5	12.8	15.1	13.7	12.7	15.0	13.7	12.6
CO, lb/h	16.5	12.9	9.6	16.0	12.6	9.4	15.2	11.9	8.9	14.1	11.0	8.4
CO, lb/MBtu (LHV)	0.0380	0.0380	0.0381	0.0380	0.0380	0.0381	0.0380	0.0380	0.0380	0.0380	0.0380	0.0380
CO, lb/MBtu (HHV)	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357
Stack SO_2 Emissions, after SO_2 Oxidation												
SO_2, ppmvd (dry, 15% O_2)	7.49	7.49	7.49	7.49	7.49	7.49	7.49	7.49	7.49	7.49	7.49	7.49
SO_2, ppmvd (dry)	8.38	7.22	6.70	8.43	7.34	6.86	8.49	7.51	6.93	8.48	7.60	6.92
SO_2, ppmvw (wet)	7.60	6.68	6.25	7.60	6.76	6.38	7.53	6.82	6.35	7.47	6.85	6.29
SO_2, lb/h	16.84	14.67	10.91	18.30	14.35	10.68	17.30	13.54	10.15	18.05	12.60	9.54
SO_2, lb/MBtu (LHV)	0.0434	0.0434	0.0434	0.0434	0.0434	0.0435	0.0434	0.0434	0.0434	0.0434	0.0434	0.0434
SO_2, lb/MBtu (HHV)	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408

4/21/2004
FMPA
Stock Island-Key West
Black & Veatch Project 136839.004
LM6000 Emissions Estimates, Revision 0

Case Number	1	2	3	4	5	6	7	8	9	10	11	12
CTG Model	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	41	59	59	59	78	78	78	95	95	95
Ambient Conditions												
Ambient Temperature, F	41.0	41.0	41.0	59.0	59.0	59.0	78.0	78.0	78.0	95.0	95.0	95.0
Ambient Relative Humidity, %	100.0	100.0	100.0	60.0	60.0	60.0	81.8	81.8	81.8	60.2	60.2	60.2
Atmospheric Pressure, psia	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696
Combustion Turbine Performance												
CTG Performance Reference	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0	0	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	41.0	41.0	41.0	59.0	59.0	59.0	78.0	78.0	78.0	95.0	95.0	95.0
CTG Compr. Inlet Relative Humidity, %	100.0	100.0	100.0	60.2	60.2	60.2	81.8	81.8	81.8	60.3	60.3	60.3
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
CTG Load Level (percent of Base Load)	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
Gross CTG Output, kW	49,848	37,389	24,923	47,966	35,975	23,986	44,705	33,532	22,353	40,695	30,524	20,348
Gross CTG Heat Rate, Btu/kWh (LHV)	8,702	9,036	10,076	8,786	9,187	10,245	8,912	9,298	10,456	9,080	9,506	10,800
Gross CTG Heat Rate, Btu/kWh (HHV)	9,268	9,623	10,730	9,357	9,784	10,911	9,492	9,902	11,136	9,670	10,124	11,502
CTG Heat Input, MBtu/h (LHV)	433.8	337.8	251.1	421.4	330.5	245.7	398.4	311.8	233.7	369.5	290.2	219.8
CTG Heat Input, MBtu/h (HHV)	462.0	359.8	267.4	448.8	352.0	261.7	424.3	332.1	248.9	393.5	309.0	234.0
CTG Water/Steam Injection Flow, lb/h	28,023	17,530	11,201	30,098	17,608	11,196	28,507	15,104	9,676	26,161	13,453	8,695
Injection Fluid/Fuel Ratio	1.2	1.0	0.8	1.3	1.0	0.8	1.3	0.9	0.8	1.3	0.9	0.7
CTG Exhaust Flow, lb/h	1,099,318	979,083	779,597	1,065,788	944,791	748,764	1,011,313	879,161	709,668	942,625	812,992	671,179
CTG Exhaust Temperature, F	814	761	763	822	789	798	837	824	820	856	853	840
Combustion Turbine Fuel												
Total CTG Fuel Flow, lb/h	23,570	18,360	13,650	22,900	17,960	13,360	21,650	16,940	12,700	20,080	15,770	11,940
CTG Fuel Temperature, F	80	80	80	80	80	80	80	80	80	80	80	80
CTG Fuel LHV, Btu/lb	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400
CTG Fuel HHV, Btu/lb	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596
HHV/LHV Ratio	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650
CTG Fuel Composition (Ultimate Analysis by Weight)												
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
H2	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%
N2	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%