BLACK & VEATCH

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Overland Park, Kansas 66211 USA

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Black & Veatch Corporation

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JUN 07 2004

BUREAU OF AIR REGULATION

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
Diane Tremor – Rose, Sundstrom & Bentley
File

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BUREAU OF AIR REGULATION

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

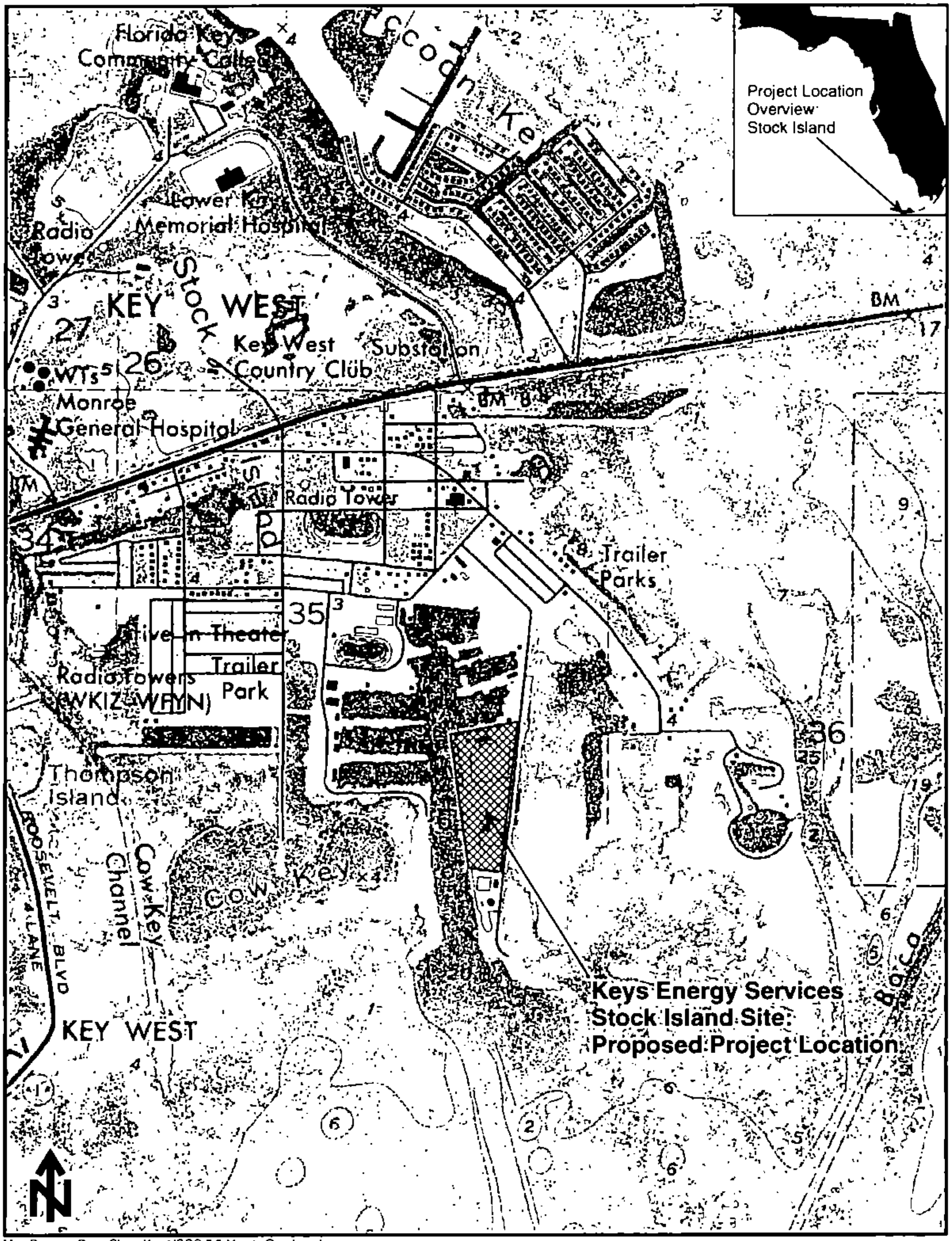
PREPARED BY
BLACK & VEATCH

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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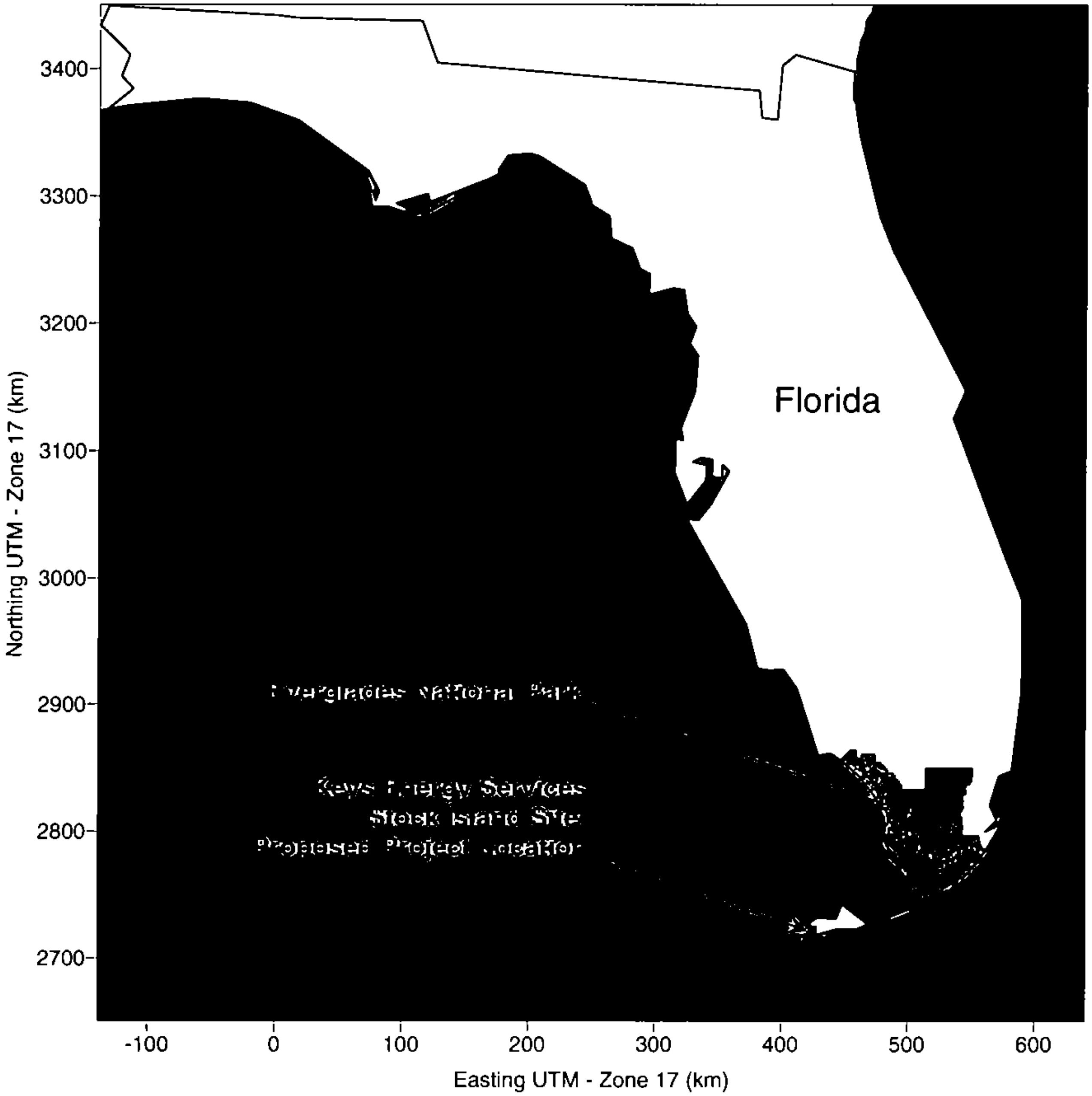
1.0 Introduction

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	Regional Haze: Highest predicted 24-hour change as processed by CALPOST. Deposition: Highest predicted annual total sulfur and nitrogen values in deposition units. Class I SILs: 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

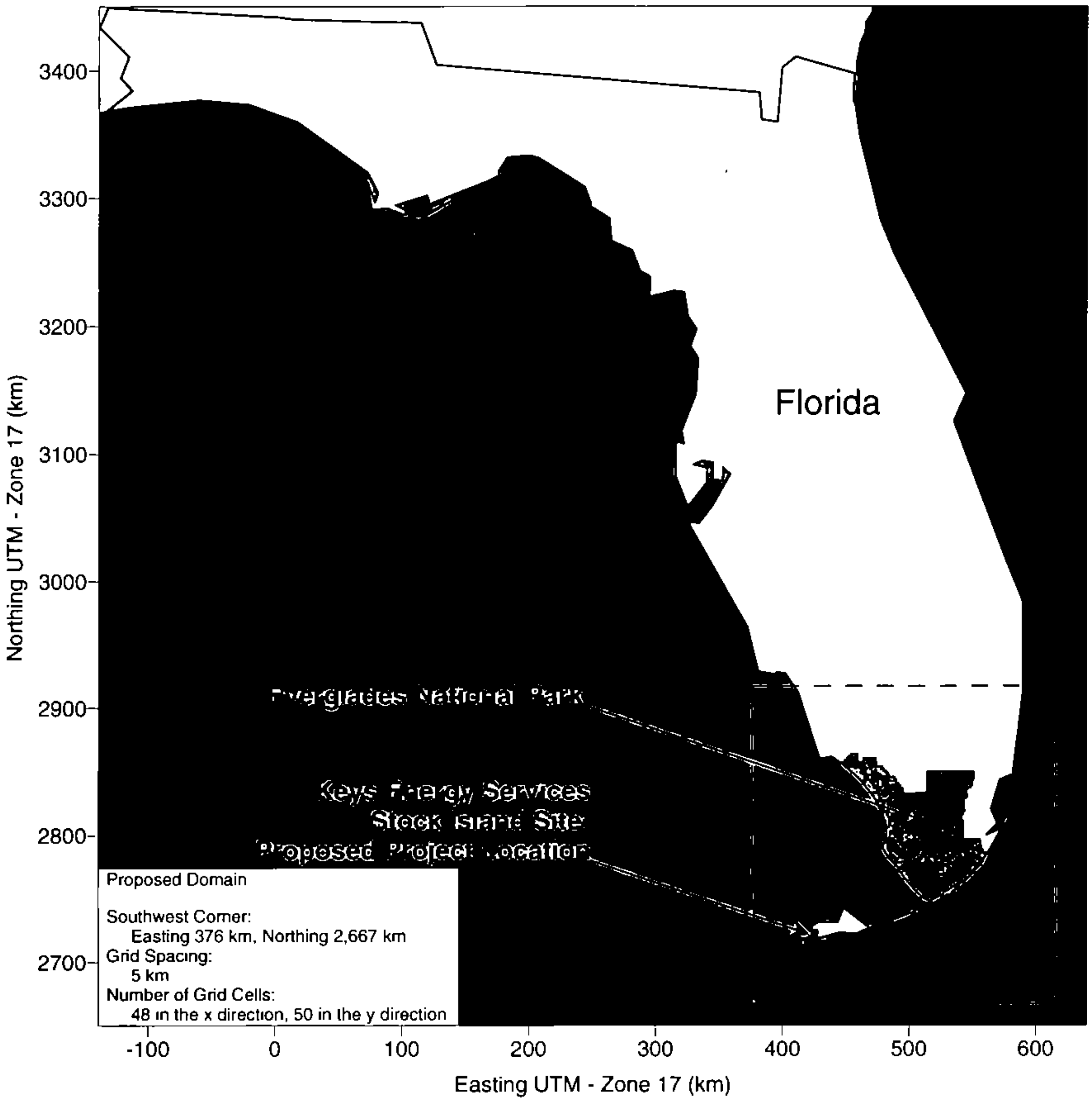
The CALMET settings, including horizontal and vertical grid coverage and resolution of prognostic mesoscale meteorological data, will be chosen to adequately characterize the area within the CALMET domain.

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 x NH_4NO_3 x f(RH) + 3 x $(NH_4)_2SO_4$ x f(RH) + 1 x 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

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Overland Park, Kansas 66211 USA

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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 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.

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.

   GE ATS

   Deltak Express

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.

(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

RECEIVED

JAN 18 2005

BUREAU OF AIR REGULATION

January 14, 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 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
D. Nelson
R. Blackburn, SD
G. Worley, EPA
J. Bunyak, NPS

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JAN 18 2005
BUREAU OF AIR REGULATION

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

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 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

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 RA13-1 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

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 vendor information from FDEP
Contingency	$4 647		$65 000	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		$1,620,946		$852,934	
Total Cost Effectiveness ($/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 NH_3 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.

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1001 James Street
PO Box 6100
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keys energy services

UTILITY BOARD OF THE CITY OF KEY WEST

February 16, 2005

RECEI
FEB 18 2005
BUREAU OF AIR R... ON

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
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

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
1	Cost Item	BACT Evaluation	2006	2007	2008	2009	2010
2							
3	Total Capital Investment	$ 4,314,000					
4							
5	Hours of Operation		1,905	2,269	2,646	3,107	3,665
6	Cumulative Hours of Operation		1,905	4,164	6,812	9,919	13,484
7	Equivalent Full Load Operating Hours		1,219	1,446	1,686	1,988	2,282
8							
9	FMPA Wholesale Rate	$ 0.05825	$ 0.05925	$ 0.06065	$ 0.06458	$ 0.06416	$ 0.06762
10	Catalyst Replacement Year		No	No	No	Yes	No
11							
12	Direct Annual Cost						
13	Catalyst Replacement	$ 383,000	$ -	$ -	$ -	$ 412,449	$ -
14	O&M	$ 70,000	$ 70,000	$ 71,750	$ 73,544	$ 75,382	$ 77,267
15	Reagent Feed	$ 49,600	$ 13,641	$ 16,584	$ 19,926	$ 23,960	$ 28,182
16	Power Consumption	$ 36,000	$ 8,924	$ 12,049	$ 15,039	$ 17,528	$ 21,198
17	Lost Power Generation						
18	Backpressure	$ 112,000	$ 30,876	$ 37,486	$ 46,789	$ 54,531	$ 66,961
19	Catalyst Replacement	$ 241,000	$ -	$ -	$ -	$ 117,338	$ -
20	Annual Distribution Check	$ 65,000	$ 55,000	$ 56,375	$ 57,784	$ 59,229	$ 60,710
21	Total Direct Costs	$ 946,500	$ 179,440	$ 194,244	$ 213,083	$ 760,416	$ 283,308
22							
23	Indirect Annual Costs						
24	Overhead	$ 42,000	$ 42,000	$ 43,050	$ 44,126	$ 45,229	$ 46,360
25	Administrative Charges	$ 93,000	$ 93,000	$ 95,325	$ 97,708	$ 100,151	$ 102,655
26	Property Taxes	$ -	$ -	$ -	$ -	$ -	$ -
27	Insurance	$ 46,000	$ 46,000	$ 47,150	$ 48,329	$ 49,537	$ 50,776
28	Capital Recovery	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000
29	Total Indirect Annual Costs	$ 655,000	$ 656,000	$ 659,525	$ 664,163	$ 668,917	$ 673,790
30							
31	Total Annualized Cost	$ 1,601,500	$ 834,440	$ 853,769	$ 877,246	$ 1,429,334	$ 927,098
32							
33	Tons Removed	135.8	37.4	44.4	52.0	61.0	70.0
34							
35	Cost Effectiveness, $/ton	$ 11,793	$ 22,297	$ 19,234	$ 16,860	$ 23,417	$ 13,236

A	B	I	J	K	L	M	N	O
1	Cost Item	2011	2012	2013	2014	2015	2016	2017
2								
3	Total Capital Investment							
4								
5	Hours of Operation	3,972	4,328	4,685	5,149	5,704	6,290	7,000
6	Cumulative Hours of Operation	17,456	21,786	26,470	31,619	37,323	43,613	50,613
7	Equivalent Full Load Operating Hours	2,542	2,770	2,998	3,296	3,651	4,025	4,422
8								
9	FMPA Wholesale Rate	$ 0.06818	$ 0.06999	$ 0.07139	$ 0.07306	$ 0.07480	$ 0.07736	$ 0.07812
10	Catalyst Replacement Year	Yes	Yes	No	Yes	Yes	Yes	Yes
11								
12	Direct Annual Cost							
13	Catalyst Replacement	$ 433,329	$ 444,163	$ -	$ 466,648	$ 478,315	$ 490,272	$ 502,529
14	O&M	$ 79,199	$ 81,179	$ 83,208	$ 85,288	$ 87,420	$ 89,606	$ 91,846
15	Reagent Feed	$ 32,188	$ 35,853	$ 39,887	$ 44,829	$ 51,016	$ 57,661	$ 64,927
16	Power Consumption	$ 23,817	$ 26,643	$ 28,414	$ 33,080	$ 37,619	$ 42,787	$ 48,073
17	Lost Power Generation							
18	Backpressure	$ 74,088	$ 82,880	$ 91,511	$ 102,916	$ 118,725	$ 133,116	$ 148,580
19	Catalyst Replacement	$ 159,440	$ 178,361	$ -	$ 221,460	$ 251,168	$ 286,436	$ 321,821
20	Annual Distribution Check	$ 62,227	$ 63,783	$ 65,378	$ 67,012	$ 68,687	$ 70,406	$ 72,166
21	Total Direct Costs	$ 864,298	$ 912,971	$ 309,397	$ 1,021,321	$ 1,090,851	$ 1,170,283	$ 1,250,821
22								
23	Indirect Annual Costs							
24	Overhead	$ 47,519	$ 48,707	$ 49,925	$ 51,173	$ 52,452	$ 53,764	$ 55,108
25	Administrative Charges	$ 105,221	$ 107,851	$ 110,548	$ 113,311	$ 116,144	$ 119,048	$ 122,024
26	Property Taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Insurance	$ 52,045	$ 53,346	$ 54,680	$ 56,047	$ 57,448	$ 58,884	$ 60,356
28	Capital Recovery	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000	$ 474,000
29	Total Indirect Annual Costs	$ 678,785	$ 683,905	$ 689,152	$ 694,531	$ 700,044	$ 705,695	$ 711,488
30								
31	Total Annualized Cost	$ 1,543,081	$ 1,596,876	$ 998,549	$ 1,715,852	$ 1,790,895	$ 1,876,979	$ 1,962,409
32								
33	Tons Removed	78.0	85.1	92.1	101.2	112.1	123.6	135.8
34								
35	Cost Effectiveness, $/ton	$ 19,771	$ 18,775	$ 10,847	$ 16,961	$ 15,980	$ 15,181	$ 14,456

A	B	P	Q	R	S	T	U	V	W
1	Cost Item	2018	2019	2020	2021	2022	2023	2024	2025
2									
3	Total Capital Investment								
4									
5	Hours of Operation	3,565	3,908	4,276	4,685	5,042	5,225	5,756	6,264
6	Cumulative Hours of Operation	54,177	58,084	62,362	67,047	72,089	77,314	83,069	89,333
7	Equivalent Full Load Operating Hours	2,282	2,500	2,736	2,998	3,227	3,344	3,683	4,009
8									
9	FMPA Wholesale Rate	$ 0.08134	$ 0.08378	$ 0.08540	$ 0.08697	$ 0.08859	$ 0.09179	$ 0.09302	$ 0.09479
10	Catalyst Replacement Year	No	Yes	No	Yes	Yes	Yes	No	Yes
11									
12	Direct Annual Cost								
13	Catalyst Replacement	$ -	$ 527,970	$ -	$ 554,606	$ 566,566	$ 582,780	$ -	$ 612,283
14	O&M	$ 94,142	$ 96,496	$ 98,908	$ 101,381	$ 103,915	$ 106,513	$ 109,176	$ 111,905
15	Reagent Feed	$ 34,337	$ 38,564	$ 43,290	$ 48,598	$ 53,604	$ 56,942	$ 64,261	$ 71,719
16	Power Consumption	$ 25,612	$ 28,776	$ 32,127	$ 35,833	$ 38,721	$ 41,947	$ 47,077	$ 52,216
17	Lost Power Generation								
18	Backpressure	$ 79,371	$ 89,533	$ 98,950	$ 111,482	$ 123,578	$ 130,502	$ 146,461	$ 162,451
19	Catalyst Replacement	$ -	$ 192,655	$ -	$ 239,884	$ 265,913	$ 280,812	$ -	$ 349,580
20	Annual Distribution Check	$ 73,969	$ 75,818	$ 77,714	$ 79,656	$ 81,648	$ 83,689	$ 85,781	$ 87,926
21	Total Direct Costs	$ 307,331	$ 1,049,814	$ 351,989	$ 1,171,533	$ 1,236,945	$ 1,283,184	$ 452,776	$ 1,448,081
22									
23	Indirect Annual Costs								
24	Overhead	$ 56,485	$ 57,897	$ 59,345	$ 60,829	$ 62,349	$ 63,908	$ 65,506	$ 67,143
25	Administrative Charges	$ 125,075	$ 128,202	$ 131,407	$ 134,692	$ 138,059	$ 141,510	$ 145,048	$ 148,674
26	Property Taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Insurance	$ 61,865	$ 63,412	$ 64,997	$ 66,622	$ 68,287	$ 69,994	$ 71,744	$ 73,536
28	Capital Recovery	$ 474,000	$ 474,000	$ 474,000	$ -	$ -	$ -	$ -	$ -
29	Total Indirect Annual Costs	$ 717,425	$ 723,510	$ 729,746	$ 262,142	$ 268,696	$ 275,413	$ 282,298	$ 289,356
30									
31	Total Annualized Cost	$ 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	70.0	76.7	84.1	92.1	99.1	102.7	113.1	123.1
34									
35	Cost Effectiveness, $/ton	$ 14,630	$ 23,108	$ 12,870	$ 15,574	$ 15,196	$ 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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015

RSMeans

Building Construction Cost Data

63rd Annual Edition

2005

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First Printing

01100 | Summary

01107 | Professional Consultant

		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

		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

		01255 Cost Indexes	CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	2005 BARE COSTS 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

GENERAL REQUIREMENTS 1

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 5^{th} 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 5^{th} 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
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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

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.

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 (

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

Jeb Bush
Governor

Northwest District
160 Governmental Center
Pensacola, Florida 32502

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

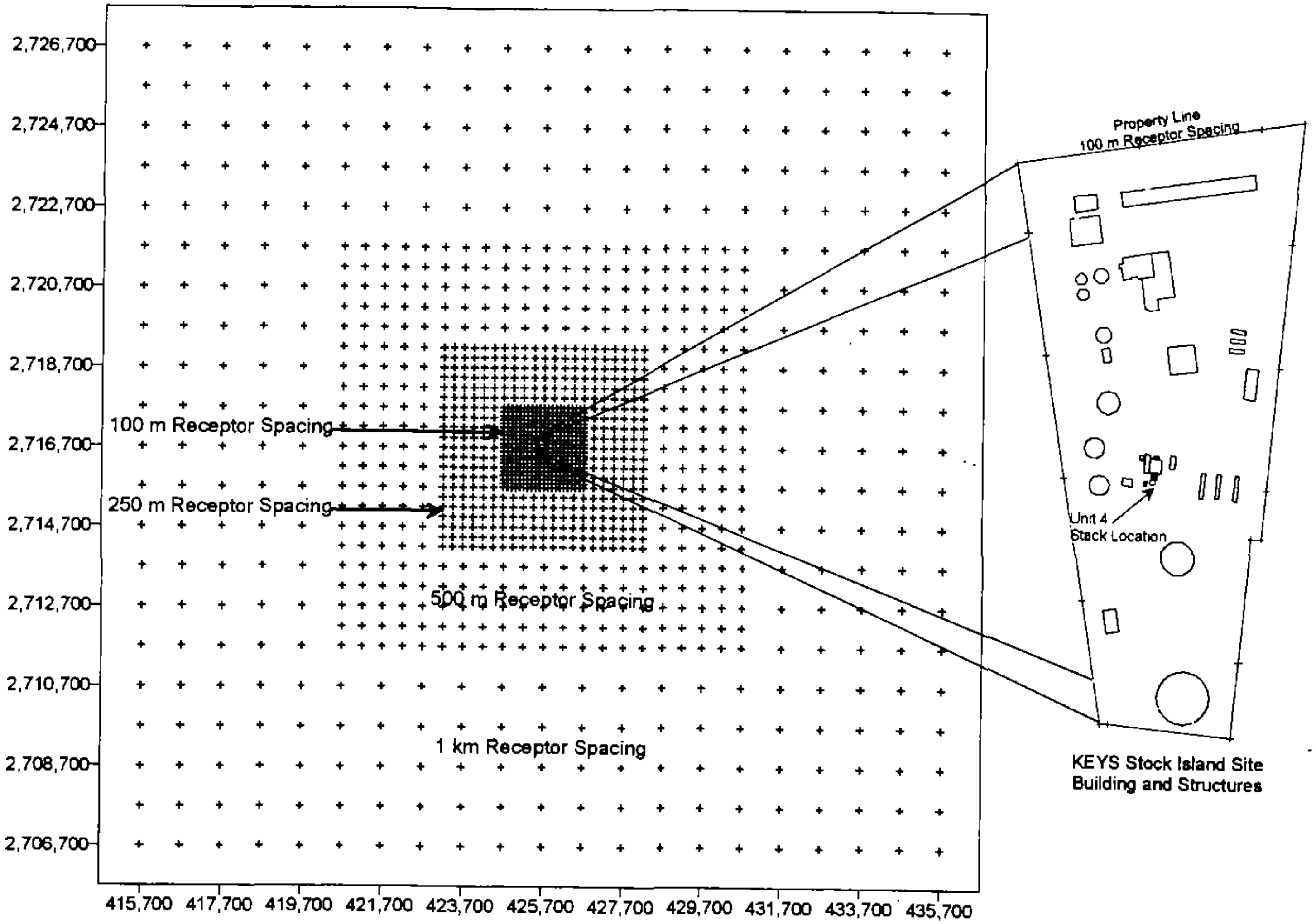


Figure 3-1
ISCST3 Class II Modeling Receptors

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] (µg/m³)	PSD Class II SIL [b] (µg/m³)	Exceed SIL?	De Minimis Monitoring Level [c] (µg/m³)	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.

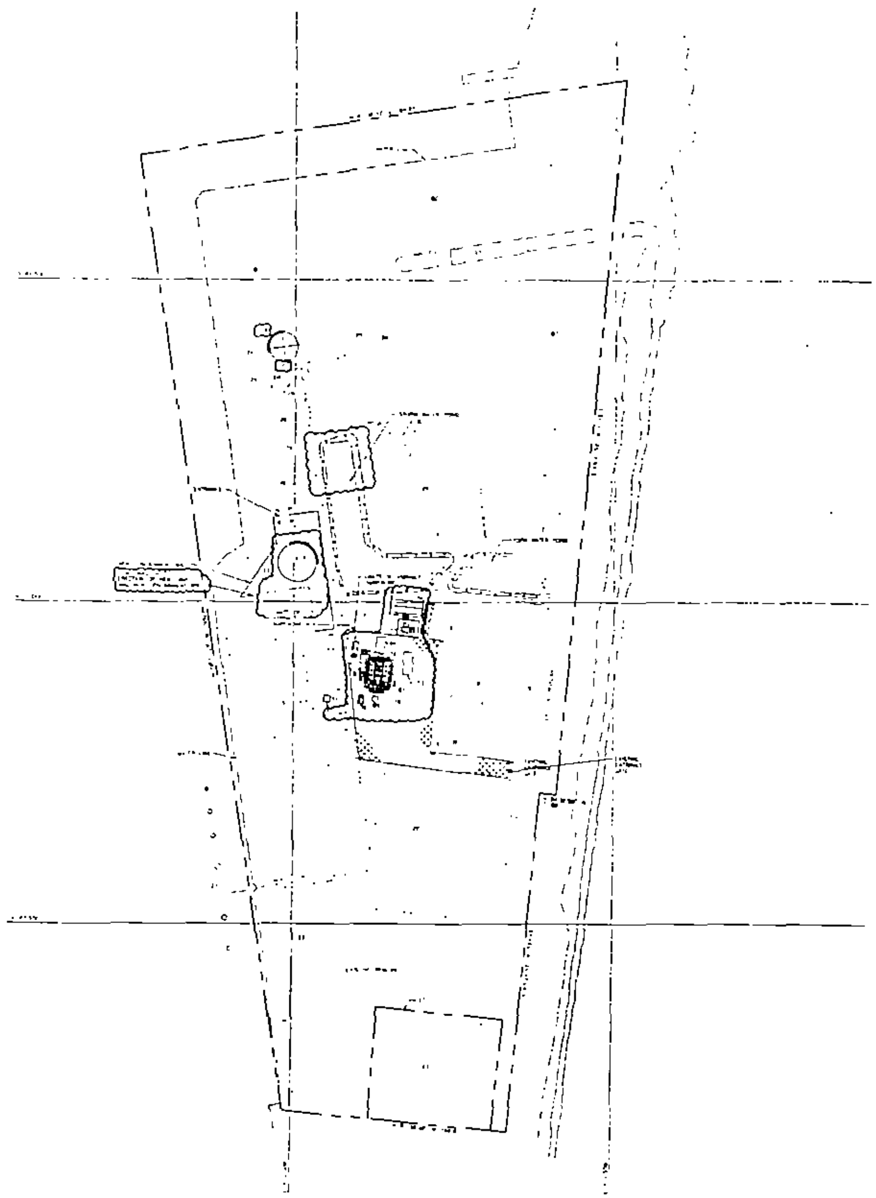
Table 4-3
Class I Significant Impact Level (SIL) Modeling Results

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



EXISTING FACILITIES LEGEND

NEW FACILITIES LEGEND

GENERAL LEGEND

NOTES

PRELIMINARY
NOT TO BE USED
FOR CONSTRUCTION

BLACK & VEATCH
CORPORATION

STOCK ISLAND
COMBUSTION TURBINE UNIT 4

136875-05-S1001

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	9 669	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	778	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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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	264,984	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)	6.70	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	6.6	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

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.

Stanley A. Armbruster
Signature

April 13, 2005
Date

(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 52 weeks/year	 7 days/week 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.)

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: 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? [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 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

AUG 0 1 2005

RECEIVED
AUG 05 2005
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

08/15/2005 12:43

=== 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 ☒

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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

Robert A. Manning

Florida Municipal Power Agency

Frederick M. Bryant
General Counsel

RECEIVED
AUG 19 2005
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
General Counsel
Florida Municipal Power Agency

Attachments

cc: Trina Vielhauer, FDEP
Al Linero, FDEP
Keith Goff, EPA
Greg Fried, OECA
Robert Manning, HGS

RECEIVED
SEP 01 2005
BUREAU OF AIR REGULATION

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

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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Director of Generation
Keys Energy Services
1001 James St.
Key West, FL ~~33401-6100~~
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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

PS Form 3800, February 2000 See Reverse for Instructions